HyPro
**A Financial Tool for Simulating Hydrogen Infrastructure
Development**

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Foreword

This report summarizes an analysis of the options and trade-offs for the establishment of the hydrogen production infrastructure necessary for a complete transition to hydrogen fuel cell vehicles by the year 2050. The primary tool used for the analysis is a custom created MatLab simulation tool entitled HyPro (short for Hydrogen Production). This report describes both the calculation methodology of HyPro and the assumptions and results of the baseline analysis and its many corollary cases. This study was made possible with funding from the U.S. Department of Energy (DOE).

The report and supporting primary analyses were overseen by Fred Joseck of the DOE Office of Energy Efficiency and Renewable Energy, Hydrogen, Fuel Cells & Infrastructure Technologies Program who provided leadership and invaluable contributions to the analysis. An Advisory Board was also established for the project to provide industry oversight and direction. The authors thank the following members for their contributions: Graham Moore & Bhaskar Balasubramanian of Chevron Technology Ventures, Mike Miller of Teledyne Energy Systems, Sandy Thomas of H2Gen Innovations Inc., Rajat Sen of Sentech, Inc., Ira Kuhn Jr. of Directed Technologies Inc., and Ed Kiczek, Air Products and Chemicals Inc.

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Executive Summary

1 Executive Summary

This report summarizes a multi-year Directed Technologies Inc. (DTI) project to study the build-out of hydrogen production facilities during the transition from gasoline internal combustion engine vehicle to hydrogen fuel cell vehicles. The primary objectives of the project are to develop an enhanced understanding of hydrogen production issues during the transition period (out to 2050) and to develop recommendations for the DOE on areas of further study. These objectives are achieved by conducting economic and scenario analysis to predict how industry would provide the hydrogen production, delivery and dispensing capabilities necessary to satisfy increased hydrogen demand. The primary tool used for the analysis is a custom created MatLab simulation tool entitled HyPro (short for Hydrogen Production). This report describes the calculation methodology used in HyPro, the baseline assumptions, the results of the baseline analysis and several corollary studies. The appendices of this report included a complete listing of model assumptions (capital costs, efficiencies, feedstock prices, delivery distances, etc.) and a step-by-step manual on the specific operation of the HyPro program. This study was made possible with funding from the U.S. Department of Energy (DOE).

HyPro calculates the expected “pump price” of hydrogen (i.e. the cost of hydrogen ready to be dispensed into a customer’s vehicle at the dispensing station) for a variety of production/delivery/dispensing pathways over a span of years. By postulating the yearly hydrogen demand and calculating which supply infrastructure pathway is expected to provide the cheapest hydrogen in any given year, a prediction of how the infrastructure would be built out over time can be created. This build-out prediction takes into consideration technology changes over time, underutilization of facilities in the early years of a station coming on line, potential stranded assets, feedstock cost differences, economies of scale in the production equipment, and “learning curve” capital cost reductions due to fabrication of multiple systems.

HyPro performs a city-based/regional analysis. Thus, it does not project the nation-wide build-out of hydrogen infrastructure, but rather the build-out associated with a specific city or region in which dispensing stations are assumed to be approximately evenly distributed. To date, the analysis has largely focused on the greater Los Angeles region.

1.1 Summary of Results & Recommendations

In January 2003, President Bush proposed \$1.2 billion in research funding to develop clean, hydrogen-powered automobiles in order to “make our air significantly cleaner and our country much less dependent on foreign sources of energy”.¹ Thus there are two primary reasons to study the technology and economics of hydrogen infrastructures. The first is to reduce emissions (both regulated and greenhouse gas) associated with passenger vehicles. Our estimates indicate that gasoline vehicles in Los Angeles emitted approximately 120,000 TPD of CO₂ emissions in 2005. Thus providing an efficient, cost-effective, clean alternative, i.e. direct

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¹ State of the Union Address. President George W. Bush, 28 January 2003.

hydrogen fuel cell vehicles, would substantially reduce passenger vehicle tailpipe emissions. With the source of emissions transferred from the individual cars to production plants one is better able to collect and discard those emissions. The second major reason for exploring hydrogen production is to reduce US dependency on foreign oil. A significant fraction of US transportation oil is of foreign origin. Thus, our domestic economy, which is dependent on transportation, is greatly impacted by the supply and price of foreign oil. A transition to a domestically sourced fuel supply, whether renewable or carbon based, would significantly reduce foreign dependence. The recommendations provided in this document are based on achieving these two goals.

1.1.1 Results of the Baseline Scenario

The HyPro model was used to examine the build-out of hydrogen production facilities in the Los Angeles California region over the years 2015 to 2050. It was postulated that hydrogen demand increased every year following a demand curve suggested by the DOE (DOE Demand Scenario 2) which culminates in 100% hydrogen fuel cell vehicle usage in 2050. Numerous assumptions went into the analysis and the reader is advised to probe the details to be found in later sections of this report.

Based on the Los Angeles Baseline Scenario:

- Based on economics alone with no outside influences, our analysis indicates that a hydrogen supply infrastructure composed of 1.5 ton per day (TPD) Forecourt Steam Methane Reformers (SMR) would naturally arise as the most cost effective hydrogen supply pathway².
- However, the dominance of 1.5 TPD SMR is largely dependent on installed capital cost. Should the depreciable capital of these production facilities be 78% higher³, then the Forecourt SMR will be important in the short run but hydrogen derived from larger central plants will be competitive at higher demands.
- Excess hydrogen from existing industrial hydrogen facilities was considered as a potentially cost effective source. We find that although existing industrial hydrogen plants may play a minor role in the very early transition period (particularly if fortuitously positioned), existing hydrogen plants even with hydrogen available at marginal cost in the early transition years will not be beneficial because 1) there isn't much surplus hydrogen available, 2) the capital required to manipulate small amounts of hydrogen for transport to distribution facilities makes the total cost of hydrogen too expensive.
- Increasing demand rates and rental property costs within city limits are not effective levers with which to modify the naturally resulting infrastructure.
- Expediting pipeline availability and using more aggressive pipeline costs similarly had no effect.
- A doubling of natural gas prices did result in a switch over to Coal Gasification technologies at demand levels of 3180 TPD and natural gas prices of \$14.22/GJ.

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² Forecourt refers to the apron of pavement in which current gasoline service stations currently dispense gasoline. In this context, a Forecourt Station is one in which hydrogen is both produced and dispensed at the dispensing station (as opposed to creating the hydrogen at a remote site and bringing it into the station via pipeline or truck).

³ Expert opinions on costs of this solution varied from an optimistic lower bound cost which was used in the baseline analysis to a pessimistic upper bound cost estimate which was as much as 78% higher than the baseline. Because of the large variation in opinion, the production option was carried through the analysis as two distinct options, a lower bound and upper bound.

- Plants that used municipal solid waste (MSW) as both a feedstock and a revenue source⁴ are competitive with the 1.5TPD Forecourt SMR. They were more cost effective than the Forecourt SMRs at when demands greater than 1420 TPD and MSW revenues greater than \$7.3/ton.
- Government mandates are the externalities which most greatly impacts how the hydrogen infrastructure will develop. Mandates for carbon sequestration or renewable feedstock tend to drive the infrastructure to central plants solutions. The earlier the mandate is implemented the higher the capital costs of the infrastructure, the lower the emissions over the transition period, and the higher the \$/kg hydrogen to the consumer. Government imposition of a carbon tax is also effective in altering the production infrastructure build-out but only when the tax is above \$132/ton CO₂.

1.1.2 Recommendations for Production Technologies

Clarify capital costs for 1.5TPD SMR systems.

Modeling suggests 1.5 TPD forecourt SMR will be the dominant low cost hydrogen production method (achieving \$2.40/kg in 2020) provided the lower bound capital cost estimates are achieved. Distributed hydrogen generation fosters the transition to hydrogen fueling and thus should be encouraged even though it itself is not a renewable technology. It is recommended that further research be dedicated to both narrowing cost estimate disparities and achieving the lower bound capital cost target for 1.5 TPD SMR systems.

Explore the role of 0.1 TPD systems during the very early years of the transition.

Analysis indicates that 0.1 TPD systems are only more cost effective than the larger 1.5 TPD systems if hydrogen demand at a single station remains below 0.3 TPD over several years. While 0.1 TPD systems could play a pivotal role in the very early years of the transition, such a low demand scenario was not the focus of HyPro modeling. Additional analysis should be conducted with a focus on 2009-2015.

Develop lower cost sequestration systems.

The naturally resulting 1.5 TPD SMR infrastructure does not help with the two objectives of transitioning to hydrogen. Those systems require natural gas and thus one is largely substituting dependency on foreign oil with dependency on foreign natural gas. In addition, there is no cost-effective sequestration system at small forecourt scale so emissions are still higher than necessary. Spending resources on lowering sequestration costs at any scale would facilitate achievement of the primary objective of hydrogen transition.

Improve efficiency and/or cost of production from renewable feedstocks.

1.5 TPD SMR infrastructure naturally results because it is the lowest cost solution over the predicted scenarios of demand levels and rates. Research efforts to decrease the capital cost or increase the efficiency of renewable hydrogen systems at many capacity levels would potentially allow it to be selected and reduce the overall carbon emissions from the infrastructure.

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⁴ In the waste disposal industry it is common for waste haulers to pay disposal facility a tipping fee for unloading. This fee was counted a revenue source (similar to a byproduct) in the MSW gasification production facilities.

Further explore Municipal Solid Waste hydrogen production systems.

Hydrogen production using Municipal Solid Waste (MSW) (i.e. trash) as a feedstock was identified as very cost competitive provided the MSW is available at a low cost. Further investigation of these systems and actual feedstock costs should be conducted.

1.1.3 Recommendations for Terminals, Delivery, and Dispensing Systems

Reduce costs of liquefaction.

Production-associated costs represent approximately 52% of total infrastructure costs, with the remaining 48% associated with terminals, delivery and dispensing operations. Delivery costs are inversely proportional to delivery volume. Analysis indicates that liquid truck transport of hydrogen is the lowest cost delivery option until demand grows large enough to support a pipeline network. However, the cost benefit of liquid transport is offset by the high capital cost and electricity requirements of hydrogen liquefaction. Consequently, focused research to improve the efficiency and reduce the capital cost of liquefaction facilities could have a substantial impact on hydrogen cost. Shifting the lowest cost pathway from that of a distributed network to that of centralized production with liquid delivery would simplify the very early years of hydrogen transition and facilitate the eventual adoption of pipelines. A major improvement in liquefaction plant capital cost or plant power demand would be a game-changer for the hydrogen transition.

Reduce high pressure storage costs.

Hydrogen storage is required at both the terminal and dispensing facilities to ensure reliable supply. Moderate/High pressure gaseous storage is a substantial cost element. Consequently, research to reduce the capital cost of stationary gaseous bulk storage is recommended.

Develop less labor intensive piping installation methods.

A large portion of pipeline installed capital costs are associated with the installation labor requirements. Since labor costs are approximately constant whether a large or small diameter pipeline is installed, pipelines are generally only cost effective at large sizes. Reducing the costs of the labor associated with pipeline installation would lower overall hydrogen delivery cost and help remote central plants be more competitive with forecourt systems.

1.1.4 Policy Recommendations

As our baseline research indicated the resulting hydrogen infrastructure build out would be 1.5 TPD forecourt SMRs. This build out does not address our primary goals of; a) reducing emissions, and b) reducing US dependency on foreign energy sources. Thus additional government assistance is necessary to further advance those goals. Our analysis indicates that further consideration of the following policies may be beneficial to meeting the emissions and independence targets.

Implement mandates to meet emission and independence objectives.

Imposing mandates is the most cost effective way for the government to drive infrastructure towards lower carbon emissions and independence from foreign resources. The implementation schedule can be immediate or gradual as needed to

meet the hydrogen program objectives. Additionally, mandates should require minimal government expenditures to deploy and enforce.

Implement government subsidies to meet emission and independence objectives.

Our analysis studied capital cost incentives of 50% and found them to be effective in shifting the infrastructure to a cleaner domestic energy source (i.e. Coal with Sequestration and Pipelines). However the necessary incentive appears to be a substantial fraction of initial capital cost. While 50% capital cost incentives are effective our recommendation is that additional studies be conducted to find the tipping point of the analysis.

1.2 Model Description

Figure 1 outlines HyPro's basic logic steps in flowchart format. HyPro estimates the expected sales price of hydrogen for all combinations of production and delivery pathways, and then each year builds an infrastructure using the lowest cost pathway identified. When viewed over multiple years, the results present a clear picture of a transition from gas to hydrogen fuel for passenger vehicles.

Figure 1: HyPro Process Map

Key features of HyPro include:

- Regional rather than national. HyPro models metro areas or other geographic regions where dispensing stations can be plausibly described as evenly distributed. It is not a national model.
- Hydrogen demand is entered by the model user and is defined at the beginning of the analysis. The model thus performs calculations and selects pathways with perfect demand foresight.
- Supply must meet or exceed demand.
- The market will allow for all hydrogen to be sold with a 10% rate of return.

- In a year where supply exceeds demand, production is normalized among all existing production options so that all plants have the same utilization.
- Infrastructure build decisions occur once a year.
- There is a potential of stranded assets but stranding of existing infrastructure components occurs only when new supply costs are below the previous' years strand price.
- All feedstocks are readily available in infinite quantities.
- Feedstock prices vary through the analysis period as projected by EIA's AEO⁵ (and adjusted for regional pricing).

This program defines a cost function used to determine the lowest cost or "winning" pathway is the expected levelized cost of hydrogen over the analysis period i.e. the total cost of hydrogen (\$/kg) that yields a specified rate of return (nominally 10% real after tax) over the analysis period (typically 10 or 20 years depending on type of facility) based on a discounted cash flow computation. The cost function is defined as:

Total H₂ Cost (\$/kg) = Production Cost + Terminal Cost + Delivery Cost + Dispensing Cost

where,

- production cost includes all steps necessary to produce and purify the hydrogen, terminal cost include preparing the hydrogen to be transported (i.e. compression for pipelines/trucks or liquefaction),
- delivery cost includes transportation costs from the production plant to the dispensing site, and
- dispensing costs include all on-site compression, storage, and dispensing into vehicles.

Within each one of these pathway components are many options and thus hundreds of potential pathways to be evaluated. Figure 2 lists all variable considered within a set of production options. For a given feedstock and production technology several permutations result from varying capacity, plant location, and sequestration capabilities.

Production Technology	Feedstock	Capacities Considered (TPD)	Locations Considered	Carbon Sequester
Gasification	Coal	15, 283, 316, 347	City Gate, Central Regional	With & Without
Steam Methane Reforming	Natural Gas	0.1, 1.5, 15, 80, 379	Forecourt, City Gate, Central	With & Without
Electrolysis	Electricity & Water	0.1, 1.5	Forecourt	Without
Steam Methane Reforming	Ethanol	1.5	Forecourt	Without

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⁵ Energy Information Agencies Annual Energy Outlook.

Nuclear	Demineralized Water	673, 719, 768	Central	Without
Reforming & Gasification	Biomass	155	Regional	Without
Reforming & Gasification	Municipal Solid Waste	150	Central	Without

Figure 2: List of Production Options

Multiple terminal options are also examined. Terminal options have a one-to-one correspondence with delivery options since the purpose of the terminal is to prepare the gaseous hydrogen from the production plant into delivery form. Figure 3 displays a listing of delivery options where:

- GT= low pressure compressed gas truck delivery
- HPGT= high pressure compressed gas truck delivery
- CryoGT= cryogenically cooled compressed gas truck⁶ (a hybrid of GT and LT where the H₂ is stored at ~80K at ~3,000psi)
- PL= hydrogen pipeline delivery
- Mixed Mode= a hybrid delivery options consisting of pipeline delivery to the edge of the city and CryoGT delivery within the city.

Option #	Name	Technology	Output Pressure (psi)	H ₂ Capacity (kg)	H ₂ Form
3,1,-2,1	GT to 0.1TPD	Low Pressure Gas Truck	2650	280	Gaseous
3,2,-2,1	HPGT to 1.5 TPD	High Pressure Gas Truck	7000	657	
3,3,-2,1	CryoGT to 1.5 TPD	Cold Compressed Truck	2000	2100	
3,4,-2,1	LT to 0.1TPD	Liquid Truck	14.7	4372	Liquid
3,4,-2,2	LT to 1.5TPD	Liquid Truck	14.7	4372	
3,5,1,1	PL to 1.5TPD (UB) ⁷	Pipeline	300	Inf.	Gaseous
3,3,-2,1	Mixed Mode ⁸	Pipeline to Cold Compressed Truck	2000	2100	

Figure 3: List of Delivery Options

⁶ This mode of storage and truck delivery has not been demonstrated but has been proposed by Air Production and Chemicals as a potentially economic mode of transport.

⁷ There is a second pipeline option, PL to 1.5TPD, which uses the Cost of Steel and Plastic Gas Distribution Pipe presented in the 2002 EEA Report to NETL Morgantown to compute the cost of the delivery pipelines. In our baseline analysis we assume a higher value of \$1M/mi to be more accurate for areas that are already developed and will require damaging and repairing existing roads and right-of-ways to bury pipelines.

⁸ The multi-mode transportation is one where a pipeline is used from the regional production facility to the city limits then a cryogenic truck is used within the city limits for delivery. In this type of infrastructure, the pipeline is within the terminal scope however the cryo truck is a delivery cost and thus the same cryo truck delivery option can be used for the multi-mode transportation options.

Lastly, the dispensing options shown in Figure 4 are tailored to receive the hydrogen from each of the delivery options and dispense it into the vehicles. All dispensing options have some level of on-site storage to accommodate hourly demand fluctuations and all options assume gaseous filling of the vehicles.

Option #	Name	H ₂ Dispensing Capacity (kg)	HP Storage Volume (kg)	LP Storage Volume (kg)	Dispensing Form
4,1,1,1	0.1TPD (GT)	100	38	280 (in Trailer)	Gaseous 5000 psi (10,000 psi in 2020)
4,4,1,1	0.1TPD (LT)			1496 (of LH2)	
4,7,1,1	0.1TPD (FC)			N/A	
4,2,1,1	1.5TPD (HPGT)	1500	358	1314 (in Trailer)	
4,3,1,1	1.5TPD (CryoGT)			2100 (in Trailer)	
4,5,1,1	1.5TPD (LT)			4488 (of LH2)	
4,6,1,1	1.5TPD (PL)			N/A	
4,8,1,1	1.5TPD (FC)		1193		

Figure 4. List of Dispensing Options

1.3 Analysis of Model Results

A key feature of the HyPro model is its ability to analyze dynamic scenarios: multi-year facility build-outs where hydrogen demand and technology can change yearly. However, we first conducted a static analysis to identify trends that are independent and dependent on demand.

1.3.1 Static (non-dynamic) Analysis

In this analysis we assume 100% utilization of equipment throughout its life then compare costs in a single build year (2030) to provide an initial comparison of options. Examining each element of the infrastructure pathway in isolation we observe the following:

- Production:
  - We observe that the use of existing⁹ Steam Methane Reformer (SMR) plants (where the plant capital cost has already been recovered and the hydrogen is sold at the marginal cost) leads to the lowest hydrogen production cost.
  - Large central coal and natural gas plants are only slightly more expensive.

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⁹ Steam methane reforming is the predominate method of hydrogen production for the current industrial hydrogen market. Those existing facilities have an estimated 5% average unused capacity at any given time. Consequently, we hypothesize that the unused capacity could be used for hydrogen vehicles. Hydrogen demand is quickly expected to outpace the excess capacity but hydrogen from existing plants could be an important element during the early years of a transition.

- There is substantial divergence in capital cost estimates¹⁰ of forecourt SMR systems. However, whether the upper bound or lower bound capital cost estimates turns out to be correct, forecourt SMR provide the lowest hydrogen cost of the forecourt options.
- Terminal and Delivery:
  - Delivery costs tend to decrease with increasing delivery capacity (i.e. liquid trucks are less expensive than gaseous trucks, and high volume pipelines are cheaper still).
  - Of the trucking options, the liquid truck has the largest capacity and the lowest delivery component costs.
  - Pipeline delivery, even with an installed cost¹¹ of \$1M/mile, is the most cost effective.
  - Gaseous truck delivery is significantly higher than the other options and it is clear that gaseous delivery would never be selected in a mature hydrogen economy but would only have application (potentially) in the very early phase of a hydrogen transition where hydrogen demand at a specific location is very low.
  - Cryo-truck delivery appears competitive with liquid truck delivery. However, the cryo-truck technology is technically immature and thus its true cost is quite speculative.
- Dispensing Cost:
  - Dispensing cost is very sensitive to station size below 1500kg/day: 100kg/day stations have >2x the dispensing costs of 1500kg/day stations (\$2.03/kg vs. \$0.80/kg).
  - However, there is only a negligible difference between 1500kg/day and 3000kg/day stations.

When total pathway costs are reviewed under the same static conditions we conclude:

- Forecourt SMR is found to yield the lowest hydrogen profited cost at \$2.30-\$2.80/kg.
- Pipeline delivery from large central SMR or Coal plants results in hydrogen costs of ~\$3.10/kg.
- Liquid truck delivery for large central SMR or Coal plants results in hydrogen costs of ~\$3.75/kg.

These cost results are for a static/non-changing analysis conducted at high utilization in the year 2030. Thus they should be viewed as “point results” to give an indication of cost potential under the best of conditions. Dynamic analysis is needed to better understand how infrastructure pathways will develop under a ramping hydrogen demand.

To understand how or when a smaller forecourt station could be suitable a secondary static analysis was done. Again comparing costs in a single build year, 2030, but this time at several constant demands below 1500 kg/day we observe:

- Hydrogen from 1500kg/day Forecourt SMR units less expensive than 100kg/day units.
- The larger unit's have higher efficiency and lower capital cost intensity¹².

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¹⁰ Industry discussions regarding the capital cost of 1500kgH₂/day forecourt SMR production units led us to split the forecourt SMR into two cases: an Upper Bound case (with a high capital cost) and a Lower Bound case (with a low capital cost).

¹¹ Although some data sources suggest hydrogen pipeline costs can be as low as \$200k/mile, those estimates are for rural installations. Based on anecdotal evidence, we use \$1M/mile for pipeline through urban locations.

- When hydrogen demand is very low, constantly below 300kg/day, the 100kg/day forecourt SMR systems are preferred. This is the cross-over point: above 300kg/day of hydrogen demand at a single dispensing site the 1500kg/day result in lower hydrogen cost. Below 300kg/day, using multiple 100kg/day units is most cost effective.

1.3.2 Dynamic Demand Studies for the LA Metro Baseline Scenario

HyPro differs from other hydrogen transition models because it is able to compute discounted cash flows for annually varying plant utilization. Consequently, HyPro's true value is in studying dynamic demand cases.

The Los Angeles, CA metro region is selected to test the model. Key assumptions in the LA Baseline Scenario are:

- Hydrogen demand is based on DOE Demand Scenario 2¹³ which defines LA's H₂ demand by year
- Coal gasification plants in California must sequester and dispose of their carbon emissions.
- Coal gasification plants outside of California may choose not to sequester their carbon emissions and may offer their hydrogen for sale in California. (However, such plants will necessarily incur additional hydrogen delivery costs.)
- Feedstock prices are based on Energy Information Administration (EIA) Annual Energy Outlook (AEO) prices with electricity, natural gas and coal, adjusted to CA region-specific data.

For the baseline scenario, renewable hydrogen mandates and carbon emission taxes are not imposed nor are hydrogen production credits granted. The economic case is solely based on the growing demand which must be met and assumes that suppliers will uniformly set prices to achieve a 10% internal rate of return.

HyPro produces a variety of graphical outputs one of which is the "Production Build" graph that portrays the inventory of hydrogen production facilities in each year of the analysis. Figure 5 displays the Production Build for the LA Baseline Scenario. Each block represents a year's build of a specific production option. The builds are color coded to indicated builds of a common production option; thus the fact that all builds are blue blocks indicates that all builds are 1.5 TPD Forecourt SMR plants. Thus we conclude that 1.5 TPD Forecourt SMR is the expected low cost hydrogen provider for all years of the Baseline Scenario analysis. These results are based on certain conditions being applicable, namely;

- We assume the lower bound capital cost target for 1.5TPD Forecourt SMR is achieved
- We assume carbon sequestration is not a factor in the build decision (because CO₂ from forecourt stations is not sequestered)
- We assume that adequate station area¹⁴ is available for the forecourt stations

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¹² Capital cost intensity is defined as (\$ of installed capital cost)/(kg/day of production capacity).

¹³ The DOE Demand Scenarios plot the number of fuel cell vehicles and buses introduced into various metro areas each year over an approximately 15 year period. We translated these vehicle introductions into hydrogen usage per year and then extrapolated the trend out to 2050 so as to achieve 100% fuel cell vehicle penetration of the light duty vehicle market over 38 years (2012 to 2050).

¹⁴ Hydrogen service stations are expected to replace gasoline stations during the hydrogen transition. Consequently, the square footage of hydrogen dispensing stations is of interest since they must physically fit into the constrained footprints of the typical urban service station. While all stations must have

- We assume that the EIA's projections of natural gas price are valid (even though they don't take into consideration the additional demand incurred by the entire fleet of light duty vehicles switching to hydrogen derived from natural gas)

Later in the sensitivity analysis we challenge those conditions to determine their impact on the total solution.

(approximately) the same dispensing equipment, forecourt production stations will occupy additional area. Thus, there is heightened concern that Forecourt SMR stations are "too big" for widespread incorporation as hydrogen providers.

Year	Production Plant	Qty	Year	Production Plant	Qty
2012	FC,NG-SMR,1.5 (LCLB)	40	2033	FC,NG-SMR,1.5 (LCLB)	299
2016	FC,NG-SMR,1.5 (LCLB)	19	2034	FC,NG-SMR,1.5 (LCLB)	293
2017	FC,NG-SMR,1.5 (LCLB)	45	2035	FC,NG-SMR,1.5 (LCLB)	282
2018	FC,NG-SMR,1.5 (LCLB)	56	2036	FC,NG-SMR,1.5 (LCLB)	283
2019	FC,NG-SMR,1.5 (LCLB)	68	2037	FC,NG-SMR,1.5 (LCLB)	286
2020	FC,NG-SMR,1.5 (LCLB)	73	2038	FC,NG-SMR,1.5 (LCLB)	271
2021	FC,NG-SMR,1.5 (LCLB)	78	2039	FC,NG-SMR,1.5 (LCLB)	256
2022	FC,NG-SMR,1.5 (LCLB)	85	2040	FC,NG-SMR,1.5 (LCLB)	236
2023	FC,NG-SMR,1.5 (LCLB)	89	2041	FC,NG-SMR,1.5 (LCLB)	216
2024	FC,NG-SMR,1.5 (LCLB)	107	2042	FC,NG-SMR,1.5 (LCLB)	200
2025	FC,NG-SMR,1.5 (LCLB)	115	2043	FC,NG-SMR,1.5 (LCLB)	185
2026	FC,NG-SMR,1.5 (LCLB)	166	2044	FC,NG-SMR,1.5 (LCLB)	186
2027	FC,NG-SMR,1.5 (LCLB)	192	2045	FC,NG-SMR,1.5 (LCLB)	180
2028	FC,NG-SMR,1.5 (LCLB)	219	2046	FC,NG-SMR,1.5 (LCLB)	218
2029	FC,NG-SMR,1.5 (LCLB)	244	2047	FC,NG-SMR,1.5 (LCLB)	234
2030	FC,NG-SMR,1.5 (LCLB)	266	2048	FC,NG-SMR,1.5 (LCLB)	253
2031	FC,NG-SMR,1.5 (LCLB)	284	2049	FC,NG-SMR,1.5 (LCLB)	272
2032	FC,NG-SMR,1.5 (LCLB)	334	2050	FC,NG-SMR,1.5 (LCLB)	287

Figure 5: Baseline Production Build - Lower Bound SMR Enabled

Figure 6: Price Plot for the LA Baseline Scenario

Another key output from the model is the Cost Plot, as shown in Figure 6. The Cost Plot is a line graph which plots the profited cost of hydrogen versus build year for the lowest cost pathways. The hydrogen cost shown is the levelized hydrogen sales price for an entirely new pathway built in each year rather than what is actually built. However, it is an accurate reflection of the objective function used to select a new

pathway to be built. Thus, in any given year that new capacity needs to be built, the pathway showing the lowest cost in the Cost Plot will be selected¹⁵ to be built.

Examining the Cost Plot for the baseline scenario, one observes that the cost of the lower bound forecourt SMR clearly dominates over the entire analysis period. The upper bound SMR forecourt cost is also shown in the Cost Plot and parallels the lower bound curve but at approximately \$1/kg higher value.

Other observations on the Cost Plot include:

- The existing supply (with liquid truck delivery), while inexpensive in production, isn't selected because the terminal investment for liquefaction overwhelms the production cost benefit.
- The initial downward slope of the SMR forecourt options is primarily a reflection of greater utilization of the equipment. An initial build of 40 stations was mandated to achieve adequate geographical dispersion in the first year. As demand grows, no new stations are built until the demand exceeds existing stations supply.
- The abrupt drop in cost in 2020 reflects a step change in dispensing station technology¹⁶.
- While pipeline delivery is not available until 2025, it is clear from the shape of the curves that an earlier introduction of pipelines would result in uncompetitive high cost due to a pipeline diseconomy of scale.
- Central SMR plants with pipeline delivery are one of the lowest cost options in the future (when demand is high).
- Coal plants with pipeline delivery would be cheaper than Central SMR/Pipeline but don't show up on the graph because the Baseline Scenario explicitly bans unsequestered coal pathways due to their prodigious CO₂ output.
- Central Coal plants with CCSD (carbon capture, sequestration, and disposal) and pipeline delivery offers the lowest cost pathway to a near zero carbon footprint.
- Many pathways are not shown since they were of (much) higher cost. A full display of Cost Plot results for the Baseline Scenario appears in XXXX.

1.3.3 Sensitivity Analysis

A series of sensitivity analyses were conducted to better understand the Baseline Scenario and to explore the affect of key assumptions. Build out plots, cost plots, emission data, and capital cost expenditures are all detailed in the main report for each sensitivity case examined. A brief description, the key result and a reference to the report section for further details are provided in Figure 7.

Sensitivity	Description	Key Result	Report Section
Demand	Use DOE Scenario 1 and 3 to test affects of accelerated and decelerated growth	No impact at those growth rates and this city size	5.5.1

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¹⁵ There are a few exceptions to this statement due to stranded assets and the imposition of carbon taxes and/or renewable mandates.

¹⁶ Storage and compressor capital cost are projected to decrease due to technological advance.

Availability of Existing Supply	80 kpd of supply are available at reduced cost of \$0.90/kg	No impact because costs of transport or liquefaction outweighs production cost benefit.	5.5.2.2
Capital Cost of SMR Forecourts	Challenge lower bound cost target by replacing with an upper bound	Forecourt SMRs no longer monopolize build. Existing supply has role in early years and Central SMRs in later years	5.5.2.1
Production from MSW	Production from Municipal Solid Waste under different feedstock cost assumptions	With revenues greater than \$7.30/ton from feedstock, production option with surpass SMR's cost at 2028 demand levels	5.5.2.3
Early Pipeline Introduction	Assume pipelines can be installed immediately	No impact because demand levels are insufficient	5.5.3.1
Pipeline Cost	Lower cost by use of different reference	Drops pathway cost but amount is does not affect build	5.5.3.2
Competition for Natural Gas Resources	Double feedstock cost to simulate limited supply	At \$14.22/GJ and 2034 demand levels, Coal Gasification with CCSD & pipeline overcomes Forecourt SMRs	5.5.4
Land Availability within City Limits	Double rental rates to simulate limited supply	Price paid for hydrogen increases slight however solution is the same	5.5.5
Impact of Learning Curve on Forecourt SMRs	Use a 0.97 learning factor on production of forecourt stations	No impact in price or build	5.5.6

Figure 7. Sensitivity Analyses Conducted

1.3.4 Financial Incentives

Financial incentives may be used to encourage the hydrogen build-out in particular directions by lowering the perceived cost of hydrogen. Many of the incentives applied to renewable electricity generation, could be applied to hydrogen systems, including production, storage, delivery, and dispensing stations. Consequently,

policies that are used within the renewable electricity generation sector form an appropriate source of ideas. Potential incentives considered for hydrogen include:

1. Property Tax Incentives
2. Sales Tax Incentives
3. Production Incentives
4. Accelerated Depreciation
5. Loan Guarantees
6. Grant Programs
7. Manufacturing Incentives
8. Rebate Programs
9. Carbon Tax (actually a disincentive)
10. Cap-and-Trade Programs (actually a limit/disincentive)
11. Government Subsidies Based on Floor Price

These policies can be described in economic terms within the HyPro simulation as one of three types of policies: mandates, taxes and cost credits.

Mandates are government-imposed policies that require certain actions to be taken or prohibit certain actions from being taken. An example of this is a California policy which mandates that a certain percentage of electricity generation for the state be from renewable sources.

Taxes are financial consequences to behaviors that are considered not favorable to society as a whole. The best example of this is a carbon tax levied on polluters, thereby reducing a plant's financial gains and encouraging carbon sequestration.

Cost credits are government provided funds to assist an individual company in entering a capital intensive market. Grant and rebate programs are examples of capital cost credit policies in execution.

1.3.4.1 Mandates

Two mandates are tested, a renewable feedstocks mandate and a carbon sequestration mandate. Since HyPro doesn't currently have the functionality to dictate the percentage of hydrogen production from renewable resources in a given year, we parametrically changed the years in which non-desirable options (non-renewable options) are no longer available. Implementation year was varied between 2020, 2032 and 2040. Figure 8 and Figure 82 show the expected daily emissions from the two mandate cases for each of the mandate implementation years. As expected the earlier the mandate, the faster the emissions decrease. Not shown but equally important, is the relationship of the earlier the mandate, the higher the infrastructure build-out capital cost and the higher the hydrogen cost. A renewables mandate results in lower emissions than a carbon sequestration mandate (for the same implementation year) but results in a higher hydrogen cost (\$3.85/kg vs. \$2.90/kg vs. \$2.60/kg (baseline)). Surprisingly, a renewables mandate is only slightly more capital intensive than the baseline (~\$14B vs. ~\$12B through 2050) compared to the sequestration mandate which is twice as capital intensive (\$18-\$24B). Specific details of the build-out pathways are contained in the main report.

Figure 8: Emissions profile from Renewable Mandates

Figure 9. Emissions profile from CCSD Mandates

1.3.4.2 Carbon Tax

HyPro uses a \$/kg carbon dioxide tax to mimic either a direct carbon tax or the effects of a cap-and-trade system. Both are functionally amount to the same thing since both impose a financial penalty based on \$/kg of carbon dioxide emitted. The only difference is whether policy makers statutorily set the \$/kg penalty or it is derived by the market¹⁷.

Based on industry discussions, we estimate that \$25/ton CO₂ is a typical level of carbon taxes being discussed and matches the current CO₂ trading cost in Europe. We draw several conclusions from this analysis:

1. At \$25/kg carbon tax, the hydrogen build-out is unchanged from the baseline i.e. forecourt SMR with a \$25/kg tax is still the least expensive pathway.
2. For Central SMR plants, it is less expensive to pay the \$25/kg tax than to install CCSD equipment.
3. However, for Central Coal plants, it is less expensive to install CCSD than to pay the tax (since coal plants produce much more CO₂ than do SMR plants).
4. A tax higher than \$25/kg would be necessary to force the market to switch from forecourt SMR to some lower CO₂ emitting pathway.

1.3.4.3 Capital Cost Credits

Capital cost credits have been implemented in other industries in order to promote a new technology. In the case of this study, promotion of low or non-CO₂-emitting facilities is of interest. Rebates for renewable energy systems are often between \$300k and \$1M per project but this represents less than 5% of the capital required for many plants. This amount is not significant in our analysis given that distributed stations with no form of sequestering carbon requires approximately \$2M in capital while remote stations require over \$100M. In order for capital cost credits to be effective by themselves, we tested a credit of 50% of the production, terminal, and delivery depreciable capital on CO₂-emitting facilities.

This high level of capital cost credit shifts the hydrogen build-out to Central Coal with CCSD and pipeline delivery and results in a substantial CO₂ reduction. Hydrogen cost is reduced \$0.06/kg - \$0.16/kg compared to the baseline, a relatively low amount given the \$2.76B 5-year cost of the credits. Note however, that the actual cost reduction is greater since the Coal/CCS/Pipeline is more costly than the baseline forecourt SMR, thus the cost credit erases this cost difference and then a little bit more.

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¹⁷ Note that the legislature is really setting the \$/kg penalty in a cap-and-trade system since they are the ones selecting the emissions limits. The market merely determines the \$/kg value that is needed to comply with those emission limits. Thus a carbon tax and a cap-and-trade system are effectively the same thing from HyPro's perspective; one is just more transparent than the other.

2 Introduction

2.1 Overview

Directed Technologies Inc. (DTI) has conducted a hydrogen infrastructure pathway analysis for the U.S. Department of Energy (DOE) to explore different options for the production, delivery, and dispensing of hydrogen to future fuel cell automobiles. This report summarizes the approach that was taken, the rules and assumptions that were used, the results that were generated and the different studies that were performed. Further details regarding the computational algorithms, input data, and cross checks performed are found in the appendices.

The HyPro software uses Excel as the user input interface and MatLab as the user analysis interface. All user inputs are done at the cell level in Excel worksheets. The worksheets provide a consistent and familiar interface for the user to supply researched financial and performance data. Each production, terminal, delivery and dispensing option is characterized on its own worksheet in the database. The analysis is conducted using a compiled executable version of MatLab code that does not require the user to have the full MatLab installed on his computer. The HyPro model is itself made up of several MatLab M-files, each of which is capable of a different portion of the total analysis. Results are provided in both MatLab and Excel for further study.

HyPro calculates the expected “pump price” of hydrogen (i.e. the cost of hydrogen ready to be dispensed into a customer’s vehicle at the dispensing station) for a variety of pathways over a span of years. By postulating the yearly hydrogen demand and calculating which supply infrastructure pathway is expected to provide the cheapest hydrogen in any given year, a prediction of how the infrastructure may be built out over time can be created. This build-out prediction takes into consideration technology changes over time, underutilization of facilities in the early years of a station coming on line, potential stranded assets, feedstock cost differences, economies of scale in the production equipment, and “learning curve” capital cost reductions due to fabrication of multiple systems.

HyPro performs a city-based/regional analysis. Thus, it does not project the nation-wide build-out of hydrogen infrastructure, but rather the build-out associated with a specific city or region in which dispensing stations are assumed to be approximately evenly distributed. To date, the analysis has largely focused on the greater Los Angeles region, and thus most results discussed in the second part of this report pertain to Los Angeles.

3 Definition of Scope and Terms

In order to put this analysis into context, a few terms need to be defined. These terms are used differently by various members of the hydrogen community so it is important that we define their meaning in this analysis so that results are interpreted appropriately.

- **Central:** Used to describe both plant size and location. **Central** plants are typically larger than 100 tons per day (TPD) and are situated between 30 – 60 miles beyond the city limits.
- **City Gate:** Used to describe both plant size and location. **City gate** plants are typically 10 - 100 TPD and are situated at the city limits in an industrial park area.
- **Distributed:** This refers to production options which are located on the same land as the dispensing stations. These are typically small (less than 5 TPD) and are located within the city limits.
- **Forecourt:** Used synonymously with distributed.
- **Regional:** Used to describe plant location. **Regional** plants are similar to central plants in size; however, they are located at the feedstock source. The distance

between feedstock (and thus the production plant) and the city will vary. For example, a **regional** Coal Gasification plant serving Los Angeles would be situated at Wyoming's Power River Basin Coal bed which is 1,000 miles from Los Angeles. Although the plant is no larger in size than a Central plant it could be used to service several communities along the way.

- **Remote:** This refers to production options which are not co-located with the dispensing stations. This term can be used to refer to central, city gate, or regional production facilities.
- **Production:** This refers to the plant which receives the feedstock and converts it to hydrogen. Included in the production plant scope is the carbon capture, storage and disposal (CCS&D) (except for the forecourt production option), the raw feedstock costs delivered to the plant and any compression required to have hydrogen output at 300 psi.
- **Terminal:** This is the portion of the pathway where the production plant hydrogen output is converted to the right temperature, pressure, and form for delivery. The terminal consists of compressors, pumps, liquefiers, evaporators, trucking bays and storage vessels. Because the production plants can occasionally be down for maintenance, the terminal includes enough storage to hold five days' worth of production supply.
- **Delivery:** This is the means of transporting hydrogen from the Terminal to the Dispensing Station. In this analysis, we look only at trucking and piping options. The delivery costs include material (truck or pipeline) and labor (drivers and/or maintenance) costs.
- **Dispensing:** This is the final leg of the pathway. The dispensing stations take hydrogen in the form it is delivered and convert it to 5,000 psi gaseous H₂ for dispensing into vehicle storage tanks. The components associated with dispensing are compressors, evaporators, storage vessels, dispensers, and gas detectors and safety equipment. Compressor and storage sizes and types will vary with the delivery option. For example, a liquid delivery will empty truck contents into an onsite storage vessel whereas a gaseous truck would leave behind a trailer as the storage vessel.
- **Options:** The different types of production, terminals, deliveries and dispensers. For example, Biomass Gasification is one production option.
- **Pathway:** Each unique infrastructure combination is called a **pathway**. A single production method can have up to 5 delivery options and 2 dispensing options, thereby creating multiple pathways for a given production method.
- **Infrastructure:** This analysis defines an **infrastructure** in one of two ways. If hydrogen production is carried out at the dispensing site then the infrastructure just consists of all components related to production and dispensing. However in the case where hydrogen production is done remotely, the infrastructure consists of all components related to production, terminal, delivery and dispensing.
- **Transition:** Defined as the amount of time for the region to convert from 0% hydrogen to 100% hydrogen demand for vehicles.
- **Carbon Capture, Storage & Disposal (CCS&D):** This term refers to the equipment needed to collect by-product carbon dioxide, store it at the production facility, compress it for pipeline transport, pipe it to a suitable site (such as a depleted oil field) and dispose of it through injection wells.
- **TPD:** All hydrogen production and dispensing rates are reported in metric tons per day (TPD). One TPD = 1,000 kg per day.

- **Profited Cost or Cost with Return:** This term is defined as the price of hydrogen than yields a 10% after-tax internal rate of return.
- **Discount Rate (DR):** The interest rate used in determining the present value of future cash flows.

4 Description of Model

4.1 Basic Model Structure and Operation

The general concept of the HyPro project is to create a computer simulation of the production, terminal, delivery and dispensing cost of hydrogen over a range of years. The HyPro algorithm performs economic optimization calculations for all of the infrastructure combinations (i.e. pathways). In each year, it determines which options would be built by finding the pathway with the lowest total profited cost per kilogram of hydrogen dispensed. Options selected in past years are used in determining which options are the least expensive in future years. When viewed over multiple years, the results present a clear picture of a transition from gas to hydrogen fuel for passenger vehicles. HyPro identifies the quantity, type and scale of hydrogen facilities built in each year, the most suitable delivery option, the expected cost of hydrogen at the pump (cost with return), and any stranded assets resulting from lower cost options entering the market in later years. Figure 10 outlines the HyPro optimization process.

Figure 10. HyPro Process Map

4.1.1 Input Data

4.1.1.1 Overview

The data researched for HyPro is entered into an EXCEL workbook that has a worksheet/tab for each infrastructure component option. The workbook is divided into four types of worksheets/tabs:

- **Technology:** worksheets which contain data relevant to a certain production, terminal, delivery or dispensing technology.
- **City/Region:** worksheet which contains data about the hydrogen demand, area geography and local tax conditions of the transition.

- **Global:** worksheet which contain data relevant to all technologies in a given workbook.
- **Supplemental:** worksheets which are not loaded into MATLAB and are usually used for intermediate calculations, notes, etc. Other worksheets can also contain these elements subject to certain conditions.

Technology and **global** worksheets are comprised of **variables** and **axes**. **Variables** have names, types and data, whereas **axes** have only names and definitions. A variable's or axis' name tells an m-file where and how it is used (if at all). A variable's type tells an m-file about the formatting of the data and to what axis the data should be automatically remapped. An axis is a common set of points to which multiple variables' data can be automatically remapped (remapping occurs by interpolation, extrapolation and/or deletion of data points). Figure 11 shows how all these worksheets and terms are related.

Figure 11: Diagram of EXCEL Spreadsheet Hierarchy

4.1.1.2 Worksheet Layout

Figure 12 shows a portion of a technology worksheet (global worksheets are structured similarly). Column A notifies MatLab what type of variable it is receiving. MatLab script file, CompileDatabase.m (the m-file for reading in HyPro worksheets) scans sequentially down the left most column looking for “Axis” or “Var...”, where “...” is a variable type. These and other items appearing in the leftmost column are called **tags**. The axis or variable’s name is in Column B and fixed. Column C gives the user the units for the numerical value. All user modifications should be made in Column E or greater.

Figure 12. Production Technology Worksheet

The worksheets are color coded system to facilitate data entry. The color system is summarized in Figure 13. Appendix A – Excel Database has a more detailed description of the layout design.

Input Database Color Scheme		
Gray	Commands to the MatLab compiler that parses the database	
Blue	User entered numbers; read directly into MatLab	
Orange	Calculations; read directly into MatLab	
Yellow	User entered numbers; not read directly into MatLab	
Green	Calculations; not read directly into MatLab	

Input Database Color Scheme		
	Purple	Off sheet reference; may or may not be read directly into MatLab
	Brown	Reference cell for values and equations

Figure 13. Database Color Scheme

4.1.1.3 Axes and Variables

Some typical modifications include adding a carbon tax, changing the demand or city, improving efficiency, and updating a capital equipment cost. Less common modifications are changing Internal Rate of Return (IRR), accounting for a cost credit and recalculating depreciable capital. All of these can be done in the Input Database and their impact assessed. Figure 14 describes some typical user modifications and where those modifications can be made. For a full list of variables on each type of worksheet reference Appendix A – Excel Database.

Sheet Name	Modifications	Cell Reference
City/Region Sheet	Demand	Rows 5 – 12
	Tax Rate	E4
	City Size	E13
	Minimum Station Spacing	E19
Global Sheet	Analysis Start / Stop years	E2 & E3
	Feedstock Costs	Rows 7 – 26
	Emission Taxes	Rows 52 - 58
All Production Sheets	Turning option on/off	A1
	IRR	E7
	Analysis Period	E9
	Capacity Factor	E14
	Location	E15
	Efficiency	Rows 60 – 79
	Overhead, Contingencies	Rows 32 – 53
	Emissions	Rows 94 – 100
All Terminal Sheets	Learning factor	Rows 104 -108
	Turning option on/off	A1
	IRR	E7
	Analysis Period	E9
	Capacity Factor	E14
	Depreciable Capital	Row 192 - 193
All Delivery Sheets	Turning option on/off	A1
	IRR	E7
	Analysis Period	E9
	Capacity Factor	E14
	Unit Costs	Rows 34 -35 (trucks), Rows 19, 37 (pipeline)
All Dispensing Sheets	Turning option on/off	A1
	IRR	E7
	Analysis Period	E9
	Capacity Factor	E14
	Depreciable Capital	Row 54
	Rent	Row 66
Supplemental Sheet	As needed by User, MatLab will not reference	

Figure 14. Commonly adjusted Input Fields

4.1.2 Objective Function

Our analysis attempts to predict the decision logic of a hydrogen production company seeking to supply hydrogen to the emerging hydrogen automotive vehicle market¹⁸. Simply stated, the logic is: the company wishes to maximize profit, profit may be maximized by minimizing hydrogen cost, and the most profitable pathway is that which results in lowest cost of hydrogen delivered to the pump at the dispensing station. Consequently, HyPro is built on an algorithm whose objective function is the minimization of delivered hydrogen cost.

The terminal necessary for converting hydrogen into the correct mode for delivery is assumed to be co-located with the production plant. The company is assumed to have perfect foresight of future hydrogen demand. Since businesses in reality have neither perfect nor infinite hydrogen demand foresight, we limit the analysis period for a given decision to 10 years (for distributed production options) and 20 years for all other production options to reflect a time frame of reasonable foresight. A discount rate is applied to convert future revenues and expenditures to their present value.

The words price and cost are often used interchangeably: this is incorrect. Price is difficult to predict because it includes profit (or loss) and is based on supply and demand and hence varies with market conditions. Cost, however, does not include profit and can be computed simply by knowledge of the monies incurred in production, delivery, and dispensing. Within HyPro, we use a hybrid of cost and price termed “Cost with Return” or “Profited Cost” which is defined as the price of hydrogen that yields a 10% after-tax internal rate of return. Thus, profited cost is not market price but can be used as an approximate price surrogate.

The profited cost of hydrogen at the pump consists of four components:

$$\text{Profited Cost } [\$/\text{kg}] = \text{Production} + \text{Terminal} + \text{Delivery} + \text{Dispensing}$$

Equation 1. Profited Cost Objective Function

For each production technology available, HyPro generates projected cash flows for the next n years, and then assigns the price that, if constant over the next n years, will result in an NPV of 0, given current volume projections and assuming a discount rate of DR . Both n and DR can be technology-dependent. These calculations are done the same way for the terminals, delivery, and dispensing technology options.

4.1.3 Discounted Cash Flow Operations

Equation 2 shows the pricing algorithm used to generate the profited cost of all four components. Most of the variables have a calendar year (CY) dependence that is not explicitly referred to. It is assumed that the values below refer to the values of those variables in the appropriate CY. For variables on Technology Worksheets the appropriate CY is the CY the plant was originally built (it's Build Year or BY). For Variables on the Global Worksheet (*FeedstockCosts* and *EmissionsTax*), it is the current CY. Note that for new plants being considered, BY=current CY.

While the algorithm used for Profited Cost determination is complicated, it can more simply be described as use of slope-intercept method in matrix notation to quickly determine a constant price of hydrogen that results in a net present value of zero for a set discount rate

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¹⁸ While the hydrogen demand can arise from any automotive market (hydrogen internal combustion engine vehicles or fuel cell vehicles), we implicitly assume the demand to come from fuel cell powered light duty vehicles.

after factoring in capital depreciation, replacement costs, feedstock cost, emission taxes, and subsidies.

$$\begin{aligned}
 &\text{For } i \in \text{IRRPeriod} \dots \\
 &\text{Depreciable}_i = \begin{cases} \text{CapitalDepreciable} \times (1 - \text{CapitalCostCredit}) + \text{ReplacementCosts}_0 & i = 0 \\ \text{ReplacementCosts}_i & i > 0 \end{cases} \\
 &\text{Fixed}_i = \begin{cases} \text{LandCosts} \times \text{LandRequired} \times (1 - \text{CapitalCostCredit}) \dots & i = 0 \\ + \text{FixedCostsOther}_0 + \text{FixedCostsOM}_0 & i = 0 \\ \text{FixedCostsOther}_i + \text{FixedCostsOM}_i & i > 0 \end{cases} \\
 &\text{Variable}_i = \text{VariableCostsOther}_i - \text{H2Subsidy}_i \\
 &\text{Feedstock}_i = \sum_{j \in \text{Feedstocks} \mid \text{FeedstockEnergyRatios}_{ij} \neq 0} 0036 \times 33.33 \times \text{FeedstockCosts}_{ij} / \text{FeedstockEnergyRatios}_{ij} \\
 &\text{Emissions}_i = \sum_{j \in \text{Emissions}} \text{EmissionsTax}_{ij} \times \text{Emissions}_{ij} \\
 &\text{Subtotal}_i = \text{Depreciable}_i + \text{Fixed}_i + \text{Volume}_i \times (\text{Variable}_i + \text{Feedstock}_i + \text{Emissions}_i) \\
 &\text{MACRS} = \text{MACRSDepreciation}_{\text{MACRSRecoveryPeriod}} \\
 &\text{Deduction} = \text{Subtotal} \otimes \text{MACRS} - \text{Depreciable} \\
 &\text{DR}_i = (1 + \text{IRR})^{-i} \\
 &\text{NPVOffset} = \sum_{i \in \text{IRRPeriod}} \text{DR}_i \times \text{Subtotal}_i - \text{TaxRate}_i \times (\text{Subtotal}_i - \text{Deduction}_i) \\
 &\text{NPVSlope} = \sum_{i \in \text{IRRPeriod}} \text{DR}_i \times \text{Volume}_i \times (1 - \text{TaxRate}_i) \\
 &\text{Price} = -\text{NPVOffset} / \text{NPVSlope}
 \end{aligned}$$

Equation 2: Algorithm for Component Profited Cost

4.1.4 Initial Number of Dispensing Stations

The initial hydrogen demand is expected to be very small, requiring only a handful of stations. Previous studies by energy companies indicate that if an insufficient number of new fuel dispensing stations are built, users will not transition under the perception that fuel supply is scarce. In order to avoid this chicken and egg problem, HyPro allows the user to input the maximum spacing between stations to ensure adequate coverage for a city. In the case of Los Angeles this number has been set to a maximum distance of ~6.3 miles between stations or 40 stations.¹⁹

4.1.5 Pathway Generation

4.1.5.1 Pathway Building Rules

All input data entered into HyPro are from open public literature; there are no “trade secrets” used. All decision algorithms are meant to be transparent. The build decision directly follows the pathway which yields the minimum expected hydrogen cost with return.

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¹⁹ “Analysis of the Hydrogen Infrastructure Needed to Enable Commercial Introduction of Hydrogen-Fueled Vehicles”, Margo Melendez, Anelia Milbrandt, National Renewable Energy Laboratory (NREL), March 2005, NREL/CP-540-37903 presented at the National Hydrogen Association, Annual Hydrogen Conference 2005, Washington, DC, March 29–April 1, 2005.

4.1.5.2 Multiple Pathway Builds in a Given Year

HyPro permits two or more production pathways to be built in a given year if that is calculated to be the most economical. While multiple builds rarely occur, it is most likely when new annual hydrogen demand is just slightly higher than the capacity of a large central plant. In such a case, a large central plant production facility could supply the majority of hydrogen demanded, and a smaller city gate or distributed production facility would produce the remaining demand. This two-pathway-build presumably would lead to lower hydrogen cost than if two large central plants were constructed (but underutilized) or several small plants were built.

4.1.5.3 Immediate Build

All builds are completed immediately, with the exception of pipelines and dispensing stations, which are scheduled immediately (based on future demand), but built only when needed. The details of pipelines scheduled to be built is available to the algorithm when it selects future builds.

4.1.6 Learning Curves

A “learning curve” or “learning factor” is applied to some of the pathway components to reflect the decrease in capital cost of a product as it is repeatedly produced. This approach is based on cumulative unit theory and is meant to reflect both improvements in product design and production method. Cumulative learning theory models this cost reduction as a set percentage discount for every doubling of total cumulative production. Within HyPro, the effects of learning are only included in the forecourt steam methane reforming production options (0.1 TPD and 1.5 TPD). Because the 1.5 TPD reforming production plants are the most economical option at low demand, several doublings typically occur.

4.1.7 Asset Stranding

HyPro permits the stranding of existing facilities if building of new facilities leads to a total hydrogen cost less than the “strand price” of the existing pathway. Either the whole pathway or a portion of the pathway (i.e. production, terminal, delivery, or dispensing) may be stranded. The strand price may be thought of as the variable cost of the pathway but its calculation is actually much more complicated due to replacement costs. For instance, while the variable cost of an existing plant may be quite low, its effective variable cost rises considerably if a major subsystem has reached the end of its useful life and needs to be replaced. Thus, in cases where assets are stranded, they typically become stranded in the year of a major sub-system replacement. Stranding of an asset also causes the current year's build to be reconsidered, because it may no longer be the cheapest option and/or meet demand. Typically, when an asset is stranded, the stranding asset will be increased in capacity to take over the stranded asset's production.

The computation of a strand price is analogous to that of a selling price. It is a sum of four components: Production, Terminals, Delivery and Dispensing. We start with the production facility. We define its strand price as the price such that keeping the facilities open for *any* number of years up to *n* in the future will not be profitable. This is done as follows: the algorithm again generates cash flows of the pathway for the next *n* years, and again we are interested in a constant selling price that makes an NPV of 0; however, instead of computing this NPV only over the next *n* years, we compute it over every subset of future years up to *n* (the next year, the next 2 years, the next 3 years, etc). For each of these subsets we determine a Terminal, Delivery and Dispensing price via a similar method as above – however, Dispensing uses the variable costs of a facility built in the original build year, whereas Delivery uses the variable costs of the current year (current market price). The sum of these three components is computed for the next *n* years; the minimum of all

these sums is the overall strand price. The discount rate for the each portion is 0 in the current implementation of HyPro, meaning that the computation is equivalent to determining the maximum price for which the cumulative cash flow never becomes positive over the next n years. Since our model is done from the perspective of a Production company subcontracting parts of its business, this is justified (the Dispensing and Delivery companies could easily decide to start working with another, more profitable Production facility).

4.1.8 Overbuilding and Underutilization

At times it may be more cost effective to overbuild supply in the current year with the knowledge that demand will increase in a few years and consume the complete supply. In the initial transition years where supply exceeds demand, the facility will experience underutilization in both production and dispensing. Delivery trucks are scalable so the seller would not contract out more trucks than necessary to meet demand.

4.2 Feedstock Cost

In order to produce hydrogen, raw materials need to undergo chemical conversions. These raw materials are different depending on the conversion process. Steam Methane Reforming (SMR) typically uses natural gas. Gasification is usually performed on coal. Utilities such as electricity and water are also considered feedstocks, even if they are not the primary source of hydrogen. Potential resources considered in this analysis are shown in Figure 15. Their costs are important because of their contribution to the overall cost of production.

Feedstocks Available in Analysis
Commercial Natural Gas
Industrial Natural Gas
Electric Utility Natural Gas
Commercial Electricity
Industrial Electricity
Electric Utility Steam Coal (Central)
Diesel Fuel
Biomass
Ethanol
Methanol
Gasoline
Steam
Cooling Water
Demineralized Water
Process Water
Bio-oil
Electric Utility Steam Coal (Regional)
MSW (1)
MSW (2)

Figure 15. Feedstocks in HyPro

In order to develop these inputs, we begin with the Energy Information Agency's Annual Energy Outlook (EIA AEO) feedstock price projections²⁰. This is a set of data included in the H2A body of work that predicts national prices of several commodities through 2070. Figure 16 below shows a good representation of those costs. However, our model is a regional model so our results would be more accurate with regional costs. Predicting resource prices is a daunting task, so we rely on the AEO table for the general trend of costs.

Figure 16. Regional Feedstock Costs²¹

We deviate from the AEO projections in several instances. First, ethanol pricing is not addressed in the AEO. Consequently, we examined other ethanol price projections and selected \$1.07/gal (\$13.27/GJ) as the future price of ethanol for all years. Second, biomass costs are likewise not addressed in the AEO. Biomass cost previously used in H2A analyses were considerably low (\$20/dry ton), possibly because costs for aggregating and transporting biomass to the utilization site were not included. Consequently, the cost of biomass used in this analysis is \$40/dry ton. Only one type of biomass, poplar trees, is considered to simplify the analysis. Other types can be added by user if needed for sensitivity analyses. Third, research on the transportation costs of coal indicated that regional production plants, co-located at the minemouth, would pay approximately 64% of the cost a central plant would for the coal feedstock. Consequently, a separate feedstock, 'Electric Utility Steam Coal (Regional)' was included to reflect the difference in transportation costs. Lastly, the cost of municipal solid waste (MSW) was not provided by

²⁰ Hutzler, Mary J. Annual Energy Outlook 2004 (AEO2004). DOE/EIA-0383 (2004). Energy Information Administration. January 2004.

²¹ Cohen, Jonah. 12-July-2007_(Learning Curve, Variable Regional Cost).xls DTI.

AEO. Research indicates that the cost of MSW has a wide range of values which are dependent on location and source, thus we have two categories of MSW in our feedstock list; one for getting paid to accept the feedstock at the hydrogen plant site (MSW Revenues) and another where the plant begins with feedstock revenues but ends with paying to acquire the feedstock. Additional feedstocks or variations to a current feedstock can be added by the method described in Appendix A – Excel Database.

Using the historical price data for Coal, Natural Gas, and Electricity, the appropriate multiplying factor can be applied to the general cost trend to get specific resource costs approximations for a given region. Figure 17 below identifies the regions that we have defined in this analysis and lists the appropriate multiplying factors for key feedstocks.

Ratio to the National Average Price					Ratio to the National Average Price				
Region	State	Coal	Natural Gas	Electricity	Region	State	Coal	Natural Gas	Electricity
Alaska		0.693		1.442	Mountain		0.482	0.795	0.761
Appalachia		1.171	1.107	0.721		Colorado	0.352	0.598	0.912
	Alabama	1.255	1.283	0.798		Idaho		0.833	0.652
	Kentucky	1.153	1.021	0.608		Montana	0.373	0.828	0.840
	Tennessee	1.061	1.050	0.806		North Dakota	0.669	0.850	0.747
	West Virginia	1.214	1.074	0.673		Wyoming	0.535	0.866	0.654
California		0.802		1.503	New York		1.760	0.883	1.647
Great Lakes		1.096	1.088	0.899	Northeast		2.168	1.315	1.394
	Indiana	0.966	0.943	0.732		Connecticut		1.174	1.346
	Michigan	0.991	0.984	0.911		Maine		1.340	1.272
	Ohio	1.185	1.137	0.904		Massachusetts	2.297	1.412	1.413
	Pennsylvania	1.242	1.288	1.050		New Hampshire	2.043	1.195	1.492
Gulf		0.766	1.012	0.908		New Jersey	2.164	1.458	1.350
	Arkansas	0.819	1.226	0.744		Rhode Island		1.517	1.438
	Louisiana	0.790	0.922	0.936		Vermont		1.111	1.446
	Texas	0.690	0.889	1.043	Southeast		1.730	1.113	0.905
Hawaii		2.419		2.060		Florida	1.786	1.030	1.071
Mid-Atlantic		1.144		0.969		Georgia	1.532	1.077	0.864
	DC			0.980		Mississippi	1.602	0.939	0.919
	Delaware		1.028	0.988		North Carolina	1.887	1.149	0.915
	Maryland		1.260	0.938		South Carolina	1.744	1.171	0.816
Midwest		0.589	1.071	0.836		Virginia	1.825	1.311	0.844
	Illinois	0.686	0.960	0.892	Southwest		0.964	0.908	1.011
	Iowa	0.529	1.014	0.840		Arizona	0.902	0.908	0.978
	Kansas	0.616	1.286	0.836		Nevada	1.103	1.076	1.123
	Minnesota	0.632	0.950	0.819		New Mexico	0.887	0.740	0.932
	Missouri	0.572	1.259	0.797	West		0.757	1.065	0.792
	Nebraska	0.389	0.972	0.748		Oregon	0.683	1.096	0.815
	Oklahoma	0.562	1.081	0.853		South Dakota	0.795	0.971	0.845
	Wisconsin	0.727	1.049	0.903		Utah	0.791	1.150	0.747
						Washington		1.044	0.761

Figure 17. Regional feedstock pricing

4.3 Yearly Hydrogen Demand

In order for this simulation to operate properly demand must be flat or increasing. It can never be less than the previous year's demand. Our current demand curves are based on transition scenarios which were provided by DOE. The DOE data provides rate of growth and amount of hydrogen required through the year 2025²². We extrapolate the curve such that in each scenario complete transition to hydrogen is achieved by 2050.

²² Gronich, Sigmund. 2010 – 2025 Scenario Analysis, DOE Hydrogen, Fuel Cells, & Infrastructure Technologies Program. DOE 2010-2025 Scenario Analysis Meeting: August 9-10, 2006.

4.4 Production Options / Component

There are 34 Production Technology Worksheets in the current version of HyPro. These are summarized in the Figure 18 and described further in Appendix B – HyPro Production Technology Descriptions. The output of all production technologies has been standardized to 300 psi gaseous hydrogen. Additional manipulation of hydrogen to higher pressure or liquid form is considered within the scope of the terminal or dispensing portion of the infrastructure.

Option #	Technology	Primary Feedstock	Location	H2 Output Capacity (TPD)	CCSD?	Efficiency/Cost Improvement Over Time?
1,1,1,1	Gasification (2005 ²³)	Coal	Central	283	No	No
1,1,1,2	Gasification (2015)			316		
1,1,1,3	Gasification (2025)			347		
1,1,1,4	Gasification (2005)			283	Yes	
1,1,1,5	Gasification (2015)			316		
1,1,1,6	Gasification (2025)			347		
1,1,1,10	Gasification (2005)		283	No		
1,1,1,11	Gasification (2015)		316			
1,1,1,12	Gasification (2025)		347			
1,1,1,13	Gasification (2015)		316			
1,1,1,7	Gasification (2005)		283	No		
1,1,1,8	Gasification (2015)		316			
1,1,1,9	Gasification (2025)		347			
1,2,1,1	Gasification (2005)		City-Gate		15	
1,2,1,2	Gasification (2015)					
1,2,1,3	Gasification (2030)					
1,3,1,3	Steam Methane Reforming (SMR)	Natural Gas	Central	379	Yes	Yes
1,3,1,1	Methane Reforming (SMR)		City-Gate	15	No	
1,4,1,1			Forecourt	0.1		

²³ There are three different coal technologies; one is available in 2005, one in 2015 and one in 2025.

Option #	Technology	Primary Feedstock	Location	H2 Output Capacity (TPD)	CCSD?	Efficiency/Cost Improvement Over Time?
1,5,1,2	SMR (LCLB) ²⁴			1.5		
1,5,1,3	SMR (LCUB) ²⁵			1.5		
1,8,1,1	Existing H2 Supply (SMR)		City-Gate	80		
1,5,1,4	Marginal Mix	Industrial Electricity	Forecourt	0.1	No	Yes
1,5,1,5	Electrolysis			1.5		
1,5,1,6	SMR	Ethanol	Forecourt	1.5		
1,6,1,1	Nuclear – HPE ²⁶ (2015)	De-mineralize d Water	Central	673	No	No
1,6,1,2	Nuclear – HTE ²⁶ (2030)			719		
1,6,1,3	Nuclear – SITHC ²⁶ (2030)			768		
1,7,1,1	Gasification & Reforming	Biomass	Regional	155	No	Yes
1,7,1,2						
1,9,1,1	Gasification & Reforming	Municipal Solid Waste	Central	150		
1,9,1,2						

Figure 18. Production Technology Worksheets

4.4.1 CCSD Details

CCSD stands for Carbon Capture, Storage and Disposal. This is an auxiliary subsystem contained within the overall production system to reduce emissions and properly dispose of CO₂ (and related gases) by injection into an underground formation. Figure 19 below displays the functional components of the CCSD sub-system in blue and is based on studies conducted at the UC Davis Institute for Transportation Studies²⁷. H2A provides cost information for the components in black. Costs for the components in blue are computed per the UC Davis study. In the case of Los Angeles we have assumed a CO₂ transport length²⁸ of 94 miles based on a report by Sally Benson²⁹. As the pie graph in Figure 20

²⁴ SMR (LCLB) where LCLB stands for Learning Curve Lower Bound is the 1.5 TPD Forecourt SMR with lower capital costs. No Efficiency improvements are included in the learning curve options but cost improvements occur when multiple units are built.

²⁵ SMR (LCUB) is the same technology and size as the 1.5 TPD Forecourt SMR (LCLB) however there is a large discrepancy within the hydrogen community about the installation costs associated with this option. Thus it is carried in our analysis as two options. The 1.5 TPD SMR (LCLB) is the lower cost associated with this option while the 1.5 TPD SMR (LCUB) is the higher cost associated with this option.

²⁶ There are three different nuclear technologies: High Pressure Electrolysis (HPE) which is available in 2015, High Temperature Solid Oxide Electrolyzers (HTE) is available in 2030, and Sulfur Iodine Thermochemical Water Splitting (SITHC) is available in 2030.

²⁷ McCollum, David L. and Joan M. Ogden. Techno-Economic Models for Carbon Dioxide Compression, Transport, and Storage & Correlations for Estimating Carbon Dioxide Density and Viscosity. University of California. Davis, CA. October 2006. UCD-ITS-RR-06-14.

²⁸ Distance from H₂ production plant to CO₂ injection site.

shows, the sequestration pipeline costs, at 69% of the total CCSD capital costs, are often the largest cost component of the CCSD subsystem.

No emissions are assessed for plants that use renewable fuels such as ethanol and nuclear therefore CCSD equipment is not necessary. The CCSD equipment is necessary however, in plants that use coal and natural gas as a fuel source. In these cases the CCSD system greatly reduces but does not completely eliminate emissions into the air. The emissions split between CO₂-equivalent gases sequestered in the ground and those emitted into the air are listed as production parameters in the production worksheets. If the purpose of switching LDV to hydrogen fuels is to reduce dependency on foreign oil and lower greenhouse gas emissions, then quantifying how much of the emissions are unavoidable becomes important. It allows for computation of the net decrease in emissions due to the switch to hydrogen. Additionally, carbon tax sensitivities can be explored and mandates restricting the overall amount of emissions can be tested for their impact on the infrastructure outcome. Appendix F – Computing Emissions of Production Plants describes how the emissions values are calculated for different hydrogen production plants.

Figure 19. Hydrogen Production System with CCSD

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²⁹ Benson, Sally M. Comparison of three options for Geologic Sequestration of CO₂. A case study for California. Lawrence Berkeley National Laboratory. Berkeley, CA..

Figure 20. Relation between Capital Costs of CCSD Subsystem Components

4.4.2 Production Option Descriptions

For this simulation, we have categorized production options two ways: by location and by size. Figure 21 explains how the categories are defined.

Production Categories	Location (from City limits)	Size (TPD H2)
Regional	> 100 mi.	> 100
Central	30 – 60 mi.	> 100
City Gate	0 mi. (at City Limits)	15 - 100
Distributed / Forecourt	Inside City Limits	< 3

Figure 21. Hydrogen Production Categories

Within each of these subcategories are several options and some options appear both in the Regional and Central areas since the plant size for both is the same.

4.4.2.1 Remote Production

Remote production refers to all plants which require the transport of hydrogen from the production to the dispensing site. Consequently, Regional, Central and City Gate plants are remote production facilities because they are located outside the city limits and all dispensing stations are located within city limits.

4.4.2.1.1 Regional

The regional subcategory is applicable in several situations. For example, in the case in which the feedstock is coal, the coal bed may be several hundred miles (or even several thousand miles) from a major metropolis. Sending the coal via rail to a production facility near a city can be costly and polluting. So we consider the option of locating the production facility at the minemouth and incurring the delivery costs on the hydrogen rather than the delivery costs of the feedstock. Native feedstock location is the primary reason for a

regional category. Another example would be biomass. Biomass is typically located in rural areas while hydrogen consumption is predominately occurs in urban areas. Because it is more effective to transport hydrogen than biomass, we locate Biomass-to-Hydrogen plants closer to the rural area. Because these production facilities are located at such large distances from the city, the land costs associated with them are typically low.

4.4.2.1.2 Central

The majority of our large plants are central plants. Central plants are located outside the city limits because they need lots of industrially zoned land. The land costs are obviously higher than in a rural regional area but are still much lower than at the city limits. Central plants encompass all types of hydrogen production methods, such as steam methane reforming and gasification from natural gas, coal, and municipal solid waste. Hydrogen production from nuclear is also considered a central plant for this analysis. Transportation costs for moving MSW from inside the city to a landfill a far distance from the city are increasing due to increased travel distances as conveniently located landfills become full. Thus, providing the MSW community with an option to drop their loads at the central plant location makes it economically attractive to trash haulers and environmentally acceptable to urban dwellers. Additionally, tipping fees paid to landfills can be substantial. However, by obviating landfills, these charges could potentially be paid to the hydrogen plant, thereby turning MSW into a negative cost feedstock (or at least a low cost feedstock).

4.4.2.1.3 City Gate

A few of the proven technologies, namely coal gasification and natural gas steam methane reforming have been scaled down so that they can be located at the city limits. They are plants located at relatively high priced outlying areas with small industrial parks real estate.

4.4.2.2 Distributed Production

Distributed production is synonymous with forecourt production for the purpose of this analysis. These are the cases where hydrogen production is co-located with dispensing, thus no terminal or delivery infrastructure is required. However, this also usually means that the facility, located within the city limits, has severe real estate constraints. Thus, distributed production facilities are usually small and produce only sufficient hydrogen for that dispensing station. The land area is often not bought but rather leased. Carbon sequestration systems do not scale down well to this size production facility. Even with all of these constraints, there are still many forecourt options. Hydrogen can be produced at the forecourt sizes of 0.1 TPD and 1.5 TPD through natural gas steam methane reforming or electrolysis. Additionally, an ethanol reforming plant with a 1.5 TPD capacity is explored in this analysis.

4.4.3 Production Cost Parameters

Common cost parameters used to compute the Capital Costs, O&M Costs, Discounted Cash Flow, etc. are summarized in the Figure 22. Additional parameters can be found in the input sheets in Appendix J – HyPro Input Database, however Figure 22 below provides a quick review of the primary items.

	Remote ³⁰	Distributed	
		0.1 TPD	1.5 TPD

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³⁰ Excludes Nuclear and City Gate Plants.

		Remote ³⁰	Distributed	
			0.1 TPD	1.5 TPD
Economics				
IRR	[%]	10%		
Analysis Period	[Years]	1/2 of Plant Lifetime		
Plant Lifetime	[Years]	40	20	
Capacity Factor	[% of DesignCapacity]	90%	70%	
Indirects				
Site Preparation	[% of Installed Costs]	1 - 2%	\$34,128	\$74,344
Engineering & Design	[% of Installed Costs]	10 - 13%	\$15,000	
Project Contingency	[% of Installed Costs]	15 - 25%	10%	
Up-Front Permitting Costs	[% of Installed Costs]	9 - 15%	\$15,000	
Fixed OM				
FTEs	[hours/year]	20 - 100	0	
Labor Costs	[\$/hour]	\$50.00	\$15.00	
Overhead and G&A	[% of Labor Cost]	20%	20%	
Property Tax & Insurance	[% of DepreciableCapital] per year	2%	2%	
Mat'l for Maint. & Repairs	[% of Installed Costs] per year	0.5 - 1.5%	7.0%	5.0%
Replacement Costs	[% of DepreciableCapital] per year	0.5%	Varies	

Figure 22. Production Cost Parameters

4.5 Terminal Options

Terminals are part of the infrastructure required to transition hydrogen from the remote production plant form to the delivery form. Each delivery method has different receiving pressure and temperature requirements though all production methods are designed to have a constant 300 psi release or outlet pressure. One function of the terminal is to convert the production output hydrogen into the proper input form for delivery. A second function is to address the issue of long-term storage. There are several factors such as maintenance, floods, and terrorist attacks that can disrupt the supply chain of hydrogen and bring about the need for multi-day storage³¹. Thus, terminals are the part of the infrastructure where necessary capital costs and utilities to perform these two functions are book kept.

³¹ Geologic storage is the only practical storage solution for truly long term, multi-month storage of hydrogen that would be necessary in case of severe hurricane or terrorist attack outages. However, we do not currently model geological storage within HyPro. Consequently, the multi-day storage we refer to in HyPro is for milder outages of < 14 days.

4.5.1 Process Flow Diagrams

A block diagram of a terminal is displayed in Figure 23. For illustrative purposes, we have chosen high-pressure truck delivery. The equipment and flows indicated in blue are needed for long-term storage. Long term storage is in liquid form, which requires a liquefier. Liquefiers are capital cost intensive and costly to operate, thus a smaller size unit is installed and storage amounts are built up and maintained over time. The other components are associated with the conversion process. Compressors are required to raise the hydrogen to the proper transport pressure. Some short-term high-pressure storage acts as buffer storage since filling of trucks is a batch process. Terminals for other delivery options are similar to this one and may be found in Appendix C – Terminal Process Flow Diagrams.

Figure 23. High Pressure Truck Terminal Block Diagram

4.5.2 Liquefier Details

The liquefaction process when needed is included at the terminal level of the infrastructure pathway. The process is quantified using the assumptions and values in the *H2A Hydrogen Delivery Component Model v1.0* (01/23/2005), with the following modifications:

- Liquefiers are limited to 100TPD. Plants with capacities > 100TPD use multiple equally sized smaller liquefiers³².
- Liquefier boil-off is 0.25% and storage boil-off is 0.25% per day.
- Liquefier electrical efficiency is not utilization-dependent; it is held constant at the level it would be if the plant were running at *MaxUtilization* (simulations show this is a probable operating point for plants in LA).
- Liquefaction site storage quantity is 5 days at the original *MaxUtilization*, adjusted only for liquefier boil-off (as opposed to H2A's 75% Average Utilization).
- Indirect capital costs for all aspects of the process train use the numbers suggested for a central plant in the *H2A Central Cash Flow Modeling Tool v1.0.9*—as opposed to those in the *H2A Hydrogen Delivery Component Model*³³.
- Liquefaction costs that would be a factor of Uninstalled Costs are treated as a factor of Installed Costs, as H2A has insufficient information on liquefaction installation costs.

³² Miller, R. *Air Products and Chemicals, Inc.* Personal communication. 20 December 2005

³³ Ringer, M. *NREL*. Personal communication. February 2005.

4.5.3 Terminal Option Descriptions

There are 7 terminal options that all remote production plants can be paired with. Those options are listed in Figure 24. Each terminal is designed for a specific delivery method.

Option #	Name	Input Pressure (psi)	Output Pressure (psi)	Buffer Capacity	H2 Form
2,1,-1,1	GH2 to GT	300 psi Gaseous Hydrogen	2650	8 hrs	Gaseous
2,1,-1,2	GH2 to HPGT		7000	8 hrs	
2,1,-1,3	GH2 to CryoGT		2000	8 hrs	
2,1,-1,4	GH2 to LT		14.7	5 days	Liquid
2,1,-1,5	GH2 to PL		700	N/A	Gaseous
2,2,-3,1	GH2 to PL to CryoGT (WY)		2000	8 hrs	
2,3,-3,1	GH2 to PL to CryoGT (RF)		2000	8 hrs	

Figure 24. Terminal options available in HyPro

4.5.4 Terminal Equipment & Cost Parameters

Cost parameters and equipment assumptions used to compute the Capital Costs, O&M Costs, Discounted Cash Flow, etc. of terminals are summarized in Figure 25.

Compressors	Truck	Storage	Pipeline
Qty and Size	3 x 50% moving to 2 x 50% in future		
Efficiency	80%		
Pressure Ratio/Stage	1.7		
Storage			
	Liquid	Gaseous Buffer	
Qty (in Production Days)	5	0.333	
Usable Capacity	90%	N/A	
Costs (\$/kg)	See Appendix	818 to 355 in future	
Liquid Accessories			
	LH2 Pumps	Evaporator	
Qty and Size	2 x 75%	1 x 100%	
Unit Cost	\$150/kgH2 / hr	\$8.65/kgH2	
Liquefaction			
	Liquefier	Cryo Cooler	
Max Size (TPD)	100	100	
Average % Utilization	90	100	
Learning Factor	0.9	None	
Pipeline			
	Transmission		
Length	Plant to City Limits		
Structures			
	All Terminals		
Bays	\$10,000/unit		
Piping	\$300/meter		
Building	\$50,000		
Truck Scale	\$80,000		

Indirects (% Installed Costs) All Terminals	
Site Preparation	2%
Engineering & Design	10%
Project Contingency	15%
Up-Front Permitting Costs	15%

Figure 25. Terminal Equipment & Cost Parameters

4.6 Delivery Options

4.6.1 Delivery Options Descriptions

There are 7 delivery option worksheets in HyPro as summarized in Figure 26.

Option #	Name	Technology	Output Pressure (psi)	H2 Capacity (kg)	H2 Form
3,1,-2,1	GT to 0.1TPD	Low Pressure Gas Truck	2650	280	Gaseous
3,2,-2,1	HPGT to 1.5 TPD	High Pressure Gas Truck	7000	657	
3,3,-2,1	CryoGT to 1.5 TPD	Cold Compressed Truck	2000	2100	
3,4,-2,1	LT to 0.1TPD	Liquid Truck	14.7	4372	Liquid
3,4,-2,2	LT to 1.5TPD	Liquid Truck	14.7	4372	
3,5,1,1	PL to 1.5TPD (UB) ³⁴	Pipeline	300	Inf.	Gaseous
3,3,-2,1	Mixed Mode ³⁵	Pipeline to Cold Compressed Truck	2000	2100	

Figure 26. Delivery Technology Worksheets

4.6.2 Truck Delivery Parameters

The cost components are taken from the HDSAM v1.0 component model. By varying the distance from production to city one can see that the costs outside the city limits (called the Transmission mode) and within the city limits (called the Distribution mode) are different. The costs associated with the Transmission mode vary with distance. The delivery costs inside the city limits are based on a mathematical representation of the circuitous path taken by a delivery truck, called the Average Manhattan distance. Therefore, that portion of the cost is independent of production plant location. The equation below represents the distance from the edge of a square with sides L to a point in its interior, where city area is approximated by a square.

³⁴ There is a second pipeline option, PL to 1.5TPD, which uses the XXX to compute the cost of the delivery pipelines. In our baseline analysis we assume a higher value of \$1M/mi to be more accurate for areas that are already developed and will require damaging and repairing existing roads and right-of-ways to bury pipelines.

³⁵ The multi-mode transportation is one where a pipeline is used from the regional production facility to the city limits then a cryogenic truck is used within the city limits for delivery. In this type of infrastructure, the pipeline is within the terminal scope however the cryo truck is a delivery cost and thus the same cryo truck delivery option can be used for the multi-mode transportation options.

$$\frac{5}{6}L * \frac{\int_{a=0}^L \int_{b=0}^L \int_{c=0}^L |a| + |b-c|}{L^3}$$

Equation 3: Average Manhattan Distance for Trucks within City Limits

The costs and efficiency parameters associated with the four trucking options are summarized in Figure 27.

	Low Pressure GT	High Pressure GT	Cryo GT	Liquid Truck
Volume (kgH2)	280	657	2100	4372
Tractor Costs ('000 \$)	75	75	75	75
Trailer Costs ('000 \$)	225	350	745	625
Fill Time (Hrs)	6	12	2	2
Non-Fill Time (Hrs)	1.5			1
Average Speed (mph)	30			
Fuel Efficiency (MPG)	6			
Truck Availability (%)	98			

Figure 27. Truck Delivery Parameters

4.6.3 Pipeline Delivery Parameters

The costs related to pipeline delivered hydrogen received enhanced examination due to the complexity and uncertainty of how a pipeline network would be developed within a city. Ultimately, a much simplified approximation was selected for incorporation into HyPro. The chosen approximation is based on the average additional pipeline length added for each new dispensing station and, while it is not a perfect approach, captures the key trends and is broad enough to encompass several patterns of potential pipeline build-out.

Like other build-out pathway components, pipeline delivery cost is determined by a discounted cash flow analysis of the pipeline operating and capital cost elements. Operating costs are dominated by compressor power needed to recompress the hydrogen due to friction pressure losses inside the pipelines. Capital costs are dominated by material and installation costs of the pipeline itself. Because pipelines are capital cost intensive and have relatively low operating costs, determination of pipeline installed cost is the most important step in determination of hydrogen delivery cost. Consequently, the remainder of this section will focus on how HyPro calculates pipeline capital expenditures.

Two types of pipelines are modeled within the HyPro program: transmission and distribution.

4.6.3.1 Transmission Pipelines

Transmission pipelines transmit hydrogen from the hydrogen production plant to the edge of the city (city limits). They are envisioned as a single above-ground pipeline sized to transmit the full production plant capacity. Because they are laid outside the city periphery, they are approximated as straight line runs from the production plant to the city limits. Consequently, the number of miles of transmission pipeline is merely the distance from the

city edge to the plant (typically 60 – 350 miles). Transmission pipeline costs are accounted for in HyPro terminal costs.

4.6.3.2 Distribution Pipelines

Distribution pipelines are underground lines that transmit hydrogen from the city limits to each individual forecourt dispensing station. Line pressure, diameter and layout route vary depending on specific city geography and the order in which the station build-out occurs. Because the specific build-out of the pipeline grid within the city limits is complex and subject to many considerations outside the scope of this project, a separate preliminary analysis of the pipeline build-out was conducted outside of HyPro and a simplified approximation of the build-out used within HyPro. The pipeline build-out approximation was reduced to two key variables: pipeline quantity³⁶ built in a given year and pipeline unit costs. Distribution pipeline costs are accounted for in HyPro delivery costs.

4.6.3.3 Pipeline Distance Calculations

Multiple patterns for inner city pipeline networks are possible, including rings (one, two, or more concentric rings), rectilinear grids, and arterial networks (usually running along main highways where right-of-way has already been obtained). Additionally, the sequence and rate of implementation is critical. For instance, some argue that the initial pipeline network must cover the entire city (albeit at an initially low station count) whereas others argue that an initial pipeline forming a narrow corridor bisecting the city is adequate in the early years. Obviously, there are major cost implications in building an entire pipeline network when hydrogen demand is low. Each of these decisions has an impact on the required number of total miles of pipeline to be laid as well as the timing of the pipeline build-out.

The HyPro model is based on an approximation to a minimum spanning tree approach to pipeline build-out. The minimum spanning tree algorithm calculates the minimum distance to connect all nodes distributed in a geographic region. The resulting total connection distance depends both on the number of nodes and on the specific distribution pattern of the nodes (i.e. whether the nodes are evenly spaced, randomly spaced, or heterogeneously spaced as would occur in an arterial method of pipeline build-out or if a river or mountain disrupts the build-out pattern).

As a separate investigation, DTI conducted a minimum spanning tree analysis to assess pipeline distance as a function of the number of stations and of the station distribution pattern. The minimum spanning tree algorithm was found to be too computationally slow to be incorporated into HyPro. Consequently we postulated, and ultimately incorporated, an approximation to the minimum spanning tree algorithm. The approximation is based on the average distance between stations given the total number of stations were evenly distributed over the geographic area. This distance represents the pipeline segment distance and is calculated by the Manhattan distance:

$$\text{Average Manhattan Distance (AMD)} = 1.244 * \sqrt{\frac{\text{Region\_Size}}{\frac{\text{Number\_of\_Stations} * \sqrt{3}}{2}}}$$

Equation 4. Pipeline Segment Distance

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³⁶ By pipeline quantity we mean the number of additional pipeline segments connecting new dispensing stations to the network. This is numerically equivalent to the number of new stations built in the year.

Multiplying AMD by the total number of stations yields an estimate of the total pipeline distance at a given time. The approximation was found to be a reasonable approximation for station counts in excess of seven³⁷. The approximation yields results within the results span of the actual minimum spanning tree algorithm run with differing station location distributions. Since the actual station placements are unknown (and depend on city specific parameters which make the placement computations beyond this projects scope) we judge the approximation results to be equally valid to the full algorithm results.

To determine the quantity of pipeline installed in a given year, one multiplies the pipeline segment distance (Equation 4) by the number of stations added that year. The costs associated with the delivery are then the pipeline quantity multiplied by its unit cost.

$$QtyPipe_N[mi] = AMD_N[mi] * QtyStations_N$$

$$PipeInvestment_N[\$] = QtyPipe_N[mi] * UnitCost[\$/mi]$$

Equation 5. Pipeline Costs in a Given Year, N

In the initial build-out when there is a low total station count, pipeline segment distance will be large, leading to high per station pipeline costs. Figure 28 shows that as the number of total stations increases, segment length decreases leading to lower per station pipeline spending. This is rational and in line with intuitive thinking regarding the build-out.

Figure 28: Pipeline Segment Length as a function of Stations

Looking at Equation 5, the quantity of pipeline in a given year is a function of city area (from AMD in Equation 4) and total number of stations. This is also true for the total pipeline quantity since it is simply a sum of all years. This is illustrated in Figure 29 and Figure 30. Figure 29 plots total number of stations vs. analysis year for three different station build-out rates (corresponding to DOE H2 Demand Scenarios 1, 2 and 3). While the station build-outs are significantly different, Figure 30 shows that the total pipeline quantity is independent of station build-out rate and solely a function of the total number of stations.

³⁷ The Manhattan distance calculation is based on a hexagonal geometry and seven is the minimum number of hexes in which to establish a symmetric pattern around a central hexagon.

Figure 29: Potential Build Paths to Achieve 100% Penetration

Figure 30: Cumulative Pipeline Miles vs. Cumulative Stations

Past experience with natural gas pipelines suggest that pipeline networks typically do not follow an exact central plan and are marked by periodic re-digging to expand pipeline diameter/capacity. Consequently, total cost of the pipeline network is dependent on the rate of pipeline station build-out. Hydrogen pipelines are likely to follow this pattern. The HyPro model for inner city distribution pipelines does not seek to model the details of the diameter and upgrading process of the pipeline network. Rather, the spanning tree approximation method inherently projects an approximation to this messy build-out upgrade process. Whether the final estimation is accurate is difficult to verify, but the approximation method provides an estimate that is rationally based and directionally correct regarding the important parameters not modeled explicitly.

Note also that the Manhattan distance calculations are carried out using the total number of stations not just the total pipeline stations. This is deliberate and based on the assumptions that new pipeline dispensing stations would not be distributed geographically evenly each year throughout the city but would rather be asymmetrically located in logical locations.

Thus the pipeline network would creep in from an entry point, dislocating existing non-pipeline stations as appropriate. Existing non-pipeline stations will be (predominantly) forecourt production units. Station components common with pipeline stations would remain, but non-common components (i.e. the forecourt production units) would be transported to new station locations. We judge that it is more efficient to move these production units than to prematurely force a longer pipeline segment to be built. In this manner, an overall more efficient pipeline build-out may be achieved.

As noted above, the HyPro model does not distinguish between pipeline segments of differing diameters. However, as noted in the next section, pipeline diameter may have only a limited impact on the total cost of the cost of the inner city pipeline build-out.

4.6.3.4 Pipeline Unit Costs

Transmission pipeline costs are computed using the H2A Components Model methodology³⁸. Because HyPro makes the assumption of a single transmission pipeline for each production plant, the maximum hydrogen flow is set at the peak production plant flow for the transmission lines. The flow is used to compute pipeline diameter which is an input to the pipeline cost algorithm. Costs are typically \$250k to \$400k per mile.

Distribution pipeline costs will be dominated by site-specific installation factors. Land costs are expected to be considerably higher for distribution pipelines than for the transmission lines. Additionally, distribution line costs related to working around existing buildings, highways, and underground utilities (existing power and gas lines, metros, etc.) will be considerable. Because these factors vary considerably from location to location within the metro area, we adopt a blanket \$1M per mile cost for all distribution lines for all years.

4.7 Dispensing Options

4.7.1 Process Flow Diagrams

Figure 31 is a diagram of a dispensing station. For illustrative purposes we have chosen high pressure truck delivery. You will see in the diagram that two trailers are required for onsite storage to meet dispensing station demand. A redundant compressor is assumed because of current poor compressor reliability. The high pressure storage volume is based on the amount needed to do cascade filling of the vehicle fuel tank. Process diagrams for other types of dispensing stations are in Appendix D – Dispensing Process Flow Diagrams.

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³⁸ Ringer, Matt. Delivery Component Model – Base Version. NREL. 10 July 2006.

Figure 31. Dispensing Station Components

4.7.2 Dispensing Options Descriptions

There are 8 Dispensing Technology Worksheets in the current version of the database as summarized in Figure 32. Four of the options have a 1-to-1 correlation with their delivery method. However, there are two types of stations, small (0.1TPD) and large (1.5TPD) that the liquid truck can service. Lastly, there are two types of dispensing stations that can be tied to forecourt production.

Option #	Name	H2 Dispensing Capacity (kg)	HP Storage Volume (kg)	LP Storage Volume (kg)	Dispensing Form
4,1,1,1	0.1TPD (GT)	100	38	280 (in Trailer)	Gaseous 5000 psi (10,000 psi in 2020)
4,4,1,1	0.1TPD (LT)			1496 (of LH2)	
4,7,1,1	0.1TPD (FC)			N/A	
4,2,1,1	1.5TPD (HPGT)	1500	358	1314 (in Trailer)	
4,3,1,1	1.5TPD (CryoGT)			2100 (in Trailer)	
4,5,1,1	1.5TPD (LT)			4488 (of LH2)	
4,6,1,1	1.5TPD (PL)			N/A	
4,8,1,1	1.5TPD (FC)			1193	

Figure 32. Dispensing Technology Options

4.7.3 Dispensing Equipment and Cost Parameters

Dispensing profited cost is based on a discounted cash flow analysis identical to the other pathway component costs. The equipment associated with a dispensing station is shown in process flow diagrams for this part of the infrastructure pathway. The costs associated with the equipment are based on the H2A components model. Inherent in the H2A cost numbers is technology improvement in gaseous hydrogen storage tanks and compressors that results

in unit cost reductions for both components. Figure 33 summarizes the unit costs used in this analysis for the large stations. The components associated with small stations are similar; however there is a dis-economy of scale as dispensing stations grow smaller and the capital cost per unit H2 increases for some components. The data for the small stations can be found in the Appendix E – Dispensing Cost Parameters.

Component	Cost Measure	Unit Costs ³⁹	
		Current	Future
Dispensers	(\$/unit)	\$26,880	
High Pressure GH2 Storage	(\$/kg)	\$818	\$355
GH2 Compressors	\$/ (kgH2/hr)/unit	\$4,580	\$3,000
LH2 Pumps	\$/unit	\$29,638	
LH2 Storage	\$/kgH2	\$50	
Evaporator	\$/unit	\$12,988	
Rent	\$/ft2-month	\$0.50	

Figure 33. Cost Parameters for Large Station Dispensing Components

4.8 Model Outputs

HyPro creates both graphical and tabular results. The outputs provide information about the minimum cost option as well as other pathways evaluated in the analysis. The results files are quickly defined here and described in detail below.

- **Build-Out Plot:** A bar chart showing the infrastructure options the economic simulation has selected to meet the hydrogen demand over time. There is a Build-Out Plot for each infrastructure component; production, terminal, delivery, and dispensing. Plots indicate type, quantity and year option was chosen.
- **Cost Plot:** A line graph which plots the profited cost of hydrogen for the lowest cost pathways in all analysis years. The default graph shows up to 10 pathways for a given year. That number can be adjusted as needed.
- **Capital Cost Table:** A data table that provides depreciable capital cost and quantity data about all infrastructures selected during the analysis period. Consequently, partial and total costs can be computed for implementing the infrastructure selected by the simulation.
- **Full Analysis Table:** A data table listing profited cost information at the component level (production, terminal, delivery, and dispensing) for all pathway combinations in all years of the economic simulation. This lookup table expands on the information available on the cost plot.

4.8.1 Build-Out Plot

The Build-Out Plot is available for each component of the infrastructure, namely, production, terminal, delivery and dispensing. The Y-Axis displays the volume of hydrogen in tons per day (TPD). The X-Axis is the Analysis Year, typically from 2005 through 2050. Figure 34 depicts a raw Build-Out Plot.

³⁹ These costs are taken from H2A Components model.

Figure 34. Raw Build-Out Plot

For the purpose of conveying results, the color palette is adjusted such that the same color is used for a given pathway in all analysis years. Figure 35 shows a typical adjusted production build-out plot. The figure title uses the abbreviation “Pro.” for Production. The legend provides build year, type, pathway and quantity information. The information is displayed as follows;

[COLOR BOX] [YEAR BUILT] [TAB NAME] @ [PATHWAY #] x [# of UNITS]

where,

- [COLOR BOX], an arbitrary color selected by MatLab to represent a pathway in a given year. In subsequent years, pathway does not have the same color.
- [YEAR BUILT], year in which the option was selected as lowest cost option. These are listed in sequential order with the earliest year at the top of the legend. Skipped years indicate that demand in that year has not exceeded supply and thus no new facilities were required. A non-sequential number indicates a reallocation of assets. See more below.
- [TAB NAME], the name used for the option is the tab or worksheet name in the input database. This is followed by the symbol ‘@’ which indicates that the production plant is part of a complete pathway. In the case of Figure 35, it is the name of the production option.
- [PATHWAY #], number assigned to the specific production, terminal, delivery and dispensing combination. HyPro assigns pathway numbers to each viable piece of infrastructure it creates. This number is unique to the pathway and does not vary from year to year in the same analysis. That pathway number is the same for the corresponding terminal, delivery and dispensing option in the infrastructure. It will vary from analysis to analysis depending on which options were toggled on/off in the

input database. The pathway number is followed by an 'x' symbol which indicates the end of this number.

- [# of UNITS], the quantity of units that each bar represents. In the case of production, terminal, and dispensing, this is the physical number of plants that are built in that year of the analysis. In the case of truck delivery, # of units signifies the number of trucks required for a given pathway. For pipeline delivery, the # of units is the physical number of pipeline miles laid down for a given pathway.

Figure 35. Adjusted Production Build-Out Plot

The legend entry for year 2025 in Figure 35 shows 115 1.5 TPD forecourt SMR's were built and their pathway number was 27. The legend also shows only 4 pathways selected in all of the analysis years (62, 27, 63, and 19). The second 2012 entry (pink color bar in middle of legend) is not in the format previously mentioned. This entry is indicating that between 2031 and 2032 the production plant built in 2012 was reassigned to another pathway (=>63). This can occur because a component downstream was stranded, or a downstream component's lifetime was shorter than the production plant's lifetime and thus must be replaced. Component replacement results in a new pathway number to be assigned to the production plant. Additionally there are boxes and "X's" on the graph. The boxes represent the hydrogen capacity available in a given year. The "X's" signify the city's hydrogen demand each year. Thus you can see that the code follows the simulation rule that supply must meet or exceed demand in any given year. The Build-out Plots for Terminals and Dispensing are similar to production.

Figure 36. Build-out Plot for Delivery, is slightly different. This plot has a different x and y axis for each delivery type selected during the simulation. In this case there are two types of delivery. In the top graph the Y-Axis is Volume in # of Units. The legend format is the same in all Build-Out plots. Thus the legend indicates that in 2012, and 2015 – 2017, Pathway 62 was chosen which included LT to 1.5 TPD (Liquid Trucks delivering to 1.5 TPD

dispensing stations) delivery. The number of Units, or Trucks, increases (1 in 2012, 6 in 2015, etc) then levels off. The increase is a result of the production plant increasing in utilization with respect to demand. Recall in the production build out that once the existing plant was fully utilized the pathway selection contained forecourt production. Thus the leveling off is a result of forecourt production coming online and requiring no delivery (refer to Figure 35). In the second graph the Volume is in TPD. Although the legend has been removed for purpose of clarity, based on the first build year and Y-Axis units this is a pipeline delivery. The "X's" again indicate the Demand, and as you can see the pipeline build does not satisfy the demand. This is because large quantities of forecourt plants were built which, along with the remote plants, help to meet the total demand.

Figure 36. Build-out Plot for Delivery

4.8.2 Cost Plot

As mentioned previously the cost plot graphs the profited cost of the lowest cost infrastructures. These are graphed against analysis year, showing how each pathway's price changes from year to year during the analysis. Figure 37 provides an example cost plot. The costs are computed assuming gross demand, rather than net, for each year. Several assumptions of the analysis directly affect the shape of the cost curves.

First, many options trend steeply downward in the early years. During that time demand will be low and coverage requirements will drive analysis to a high number of underutilized dispensing stations. As demand increases, those options will become fully utilized so prices will decrease. The next price drop occurs in 2020 and resembles a step function. Technology jumps assumed in all compressors and storage vessels attribute to this drop. Third, in the year 2025 some options are just beginning. Certain technologies are not available until that year, namely pipelines and hydrogen from nuclear feedstock. Last, some options begin to trend upward in the final third of the analysis. This is a result of the feedstock prices increasing in the out years.

The legend for this plot provides the names of each component in the infrastructure separated by a '='>' symbol. The legend lists every pathway shown in the figure in the format;

[MARKER] [PROD TAB NAME] => [TERM TAB NAME] => [DEL TAB NAME] => [DISP TAB NAME]

or, in the case of forecourt production pathways

[MARKER] [PROD TAB NAME] => [DISP TAB NAME]

where,

- [MARKER], arbitrary color line and marker assigned by MatLab to that pathway.
- [PROD TAB NAME], production worksheet name (also production plant) from input database that is part of this pathway.
- [TERM TAB NAME], terminal worksheet name (also terminal station) from input database that is part of this pathway.
- [DEL TAB NAME], delivery worksheet name (also delivery method) from input database that is part of this pathway.
- [DISP TAB NAME], dispensing worksheet name (also dispensing station) from input database that is part of this pathway.

Thus, we see that the lowest cost option in 2015 is the cyan line, which in the legend corresponds to "FC, NG-SMR, 1.5 => 1.5 TPD (FC)". This is distributed natural gas SMR facilities of 1.5 TPD capacity paired with the corresponding dispenser stations. The costs computed are from the discounted cash flow analysis using all the parameters mentioned in previous sections of this document.

This line graph is useful when used with the build-out plot as it provides the pricing that was used to select the infrastructure. It's clear that in 2015 the forecourt station is the most economic; however, beyond 2032 the cost differentiation between a forecourt and a central option has narrowed to less than \$0.10/kg H₂. Since many of these technologies are not proven, it is entirely possible that the error bounds of a given pathway are greater than the cost difference between pathways. Manual data analysis is the key in these cases.

Figure 37. Cost Plot

4.8.3 Capital Cost Table

The Build-out table simply lists which pathway was selected in every analysis year by component and provides the costs associated with each component. The table columns are:

- Year – The build year for the technology
- Tech – The technology that was selected
- Path – The pathway number associated with the technology
- Qty – The number of units to be built to satisfy net demand
- DepCap (ea.) – Depreciable Capital of one unit of that technology
- Learning – The learning factor specified for that technology
- DepCap (total) – The total cost of all units built of that technology with the learning factor applied.
- Miles – number of pipeline miles need, if the technology column indicates pipelines.

Total costs for implementing the infrastructure selected are computed by taking the sum of the DepCap (total) column. If one is interested in the capital cost expenditures on a year-by-year basis, pivot tables and data sorts can accomplish this task. This information becomes important when one further analyzes the most costly part of the infrastructure: production, terminals, dispensing or delivery.

4.8.4 Full Analysis Table

Unlike the Capital Cost table which only lists the winning pathways, this data table records values for all of the pathways computed by HyPro. The profited cost for each component of an infrastructure and the total profited cost of the pathway are stored here. The data is similar to that used to construct the Cost Plot, extracted to the component level. The columns in the table are:

- Pathway – The number the simulation has assigned to the pathway
- Year – The calendar start year of the analysis

- Production – The profited cost of the production component of the pathway
- Terminal – The profited cost of the terminal component of the pathway
- Delivery – The profited cost of the delivery component of the pathway
- Dispensing – The profited cost of the dispensing component of the pathway
- Total Cost – The total profited cost of the pathway
- Path Details – The names of the production, terminal, delivery and dispensing components that make up the pathway

This data can also be sorted by year or pathway to see trends in data and determine the largest contributors to the total pathway cost.

5 Analysis of Model Results

This section of the report provides key results that we have found by running the HyPro model. The model is dynamic, meaning that it analyzes changing annual hydrogen demand and computes the proper operating costs and resulting hydrogen cost associated with varying plant utilization. While many case studies have been conducted with the model, a few cases best illustrate the key factors influencing cost - these will be the main focus in this section.

5.1 Production Plant Capital Cost Intensity

While many factors affect the production cost of hydrogen, the top three factors are capital cost, efficiency, and feedstock cost. To gain perspective on capital cost, which varies significantly between production methods and production scales, we define capital cost intensity as the total installed capital cost divided by the design hydrogen production rate. Thus specific capital cost has units of \$/ (kg/day).

Figure 38 lists the installed capital costs and rated production capacities for the primary production methods analyzed in the baseline scenario. Figure 39 graphs the resulting capital cost intensity versus daily hydrogen production rate. Several trends are observed:

- Increases in plant capacity generally lead to lower capital cost intensity. This is evident by the downward trend of the cost intensity values within a production method (such as SMR).
- Coal plants tend to be more capital intensive than natural gas plants.
- Nuclear plants tend to be very large and very capital intensive.
- Biomass plants tend to be somewhere between SMR and coal plants in capital cost intensity.
- There is considerable spread in the capital cost intensity of 1500kg/day SMR units due to uncertainty of the installed cost estimates (Lower bound vs. Upper bound estimates) and potential cost reductions made possible by building multiple units in a factory setting (i.e. the learning curve).
- Electrolysis capital costs, which are based on DOE future projections, might have lower capital cost intensity than distributed SMR units.
- Ethanol plants have capital costs comparable to SMR plants.

Of course, production plant capital cost is but one component of total delivered hydrogen cost. However, identification of the relative capital intensity of each production method and the trend with scale may lead to greater understanding of the overall hydrogen build-out.

Hydrogen Production Plant	Rated Capacity, kg/day	Total Installed Capital Cost*
Biomass Gasifier: Central	155,236	\$138,229
Coal Gasifier: City Gate	15,000	\$56,715
Coal Gasifier: Central	316,000	\$371,620
Coal Gasifier with CCS-Central	316,000	\$489,803
Electrolyzer: Small Distr.	100	\$358
Electrolyzer: Large Distr.	1,500	\$1,487
SMR: Small Distr. For 180th unit	100	\$386
SMR: Small Distr. For 500th unit	100	\$372
SMR: Large Distr., Lower Bound For 3rd unit	1,500	\$1,261
SMR: Large Distr., Lower Bound For 500th unit	1,500	\$1,061
SMR: Large Distr., Upper Bound For 3rd unit	1,500	\$2,243
SMR: Large Distr., Upper Bound For 500th unit	1,500	\$1,888
SMR: City Gate	15,000	\$13,699
SMR: Central	379,387	\$135,532
Ethanol: Large Distr.	1,500	\$1,265
Nuclear: High Temp Electrolysis (Yr 2025)	719,395	\$2,141,767
Nuclear: Sulfur-Iodine (Yr 2025)	767,783	\$1,856,930

* Yr 2015 cost unless otherwise noted.

Figure 38: Summary of Production Plant Capital Costs and Capacities

Figure 39: Production Plant Capital Cost Intensity

5.2 Static Demand Cost Comparisons

5.2.1 High Static Demand

The most basic study we need to consider relates the costs of the different components in the hydrogen infrastructure (production, terminal, delivery, and dispensing) to each other. The best way to do this is with a large, non-changing or static hydrogen demand over the analysis period so costs reflect fully utilized components. A city area is also needed to determine the delivery costs and required quantity of dispensing stations. Since Los Angeles is later used in the baseline scenario, its area and hydrogen demand in the year 2030 are used to perform static demand cost comparisons. Static demand cost comparisons can be made for any year: we choose the year 2030 because all technology advancements are put into effect by that year.

5.2.1.1 Comparison of Remote Production Costs

The HyPro program computes the price of hydrogen production using a few key parameters such as: IRR, Depreciable Capital, O&M Costs, Feedstock Efficiency & Costs, Replacement Costs, and Capacity Factor. Based on these assumptions, a discounted cash flow calculation is then performed to determine the required selling price to achieve the prescribed IRR, for the anticipated demand. The profited costs of several remote production options are shown in Figure 40. For a complete list of assumptions associated with each production facility, see Appendix J – HyPro Input Database.

Figure 40 shows the expected production-only costs from the remote production options considered. The option labeled EXISTING Hydrogen entails purchasing surplus hydrogen from an existing production facility. It is the most economical since it represents only variable cost, with no capital repayment being required: a valid assumption since the plants are already constructed and can sell surplus hydrogen at their marginal cost. Hydrogen derived from Coal Gasification is the next least expensive option. However, the carbon dioxide produced from this method is quite large. The cost associated with carbon capture, storage & disposal (CCS&D) is substantial as can be seen by comparing Coal Gasif (Regional) and Coal Gasif with CCSD (Regional) in Figure 40. Hydrogen from biomass, specifically poplar trees at \$40/ton (2008), is observed to be relatively expensive even though the hydrogen facility is situated close to the biomass feedstock source. Location impacts the price of land for the production facility. The production plants in Figure 40 with the label (Central) are all located 60 miles from the city center. The BIOMASS Gasif. option is located 350 miles from the city center, COAL Gasif. (Regional) options are located 1000 miles from the city center at the coal bed and the EXISTING Hydrogen option is found at the city limits. More significantly, production plant location affects the delivery costs of hydrogen. However, Figure 40 reflects only production costs: delivery costs will be shown in a later comparison.

Figure 40: Remote Production Costs at High Utilization and Demand

5.2.1.2 Comparison of Distributed Production Costs

Similar to Figure 40, distributed (or forecourt) production costs are compared in Figure 41. One can immediately see that distributed production is significantly more costly than the production-only costs from large remote plants. However, keep in mind that distributed production pathways do not incur delivery costs, while remote plants do. The distributed production methods use water, ethanol, or natural gas as their main feedstocks. Steam methane reforming (SMR) is the primary method of producing hydrogen from natural gas⁴⁰. Despite considerable research on this topic, a wide dispersion still exists on the expected installed capital cost of the production equipment at the 1.5TPD forecourt scale. Thus, this pathway is treated parametrically with both a lower bound and an upper bound capital cost estimate to bracket the range of potential hydrogen costs (see Figure 38). While all of the production options have an error band associated with their capital costs and resulting hydrogen prices, the distributed SMR is of particular interest because it is the lowest cost distributed option and has an unusually wide range of industry estimated capital cost.

Figure 41: Distributed Production Costs at High Utilization and Demand

5.2.1.3 Comparison of Terminal and Delivery Costs

While the production cost of hydrogen from remote large-scale plants is low (less than \$2.50/kg in all cases), there are additional costs associated with the transport of hydrogen from the plant to its point of use within the city limits, namely terminal and delivery costs. Distributed production plants don't incur these costs since production is completed at the point of dispensing. Consequently, one must determine whether the low cost of remote large-scale production more than offsets the required transport costs.

⁴⁰ Partial oxidation (POX) reforming (and POX derivatives) remains a viable alternative to steam reforming (SMR) at small scales but there is a general consensus in the community that at scales near 1500kgH₂/day, SMR is the preferred option due to its higher efficiency.

Figure 42 shows the costs of the various delivery options in the project scope. For illustrative purposes, we have applied delivery costs to a common remote production option (NG SMR with CCS&D (Central)). The red bars represent the cost of terminals which must be built in order to transform the hydrogen to the desired delivery form. Terminal costs are high for liquid truck delivery because costly, energy-intensive liquefiers are necessary. Without yet knowing the total pathway costs, we can see that terminal and delivery costs add significantly to production cost, often increasing the cost by a factor of two. This is significant because the remote production options become more expensive than the upper bound SMR forecourt station (last column in Figure 42).

Figure 42 also grants additional insights:

- Delivery costs tend to decrease with increasing delivery capacity i.e. liquid trucks are less expensive than gaseous trucks, and high volume pipelines are cheaper still.)
- Of the trucking options, the liquid truck has the largest capacity and the lowest delivery costs.
- Pipeline delivery, even with an installed cost of \$1M/mile, is the most cost effective.

The hydrogen pipeline installed capital cost is based on data from natural gas pipelines which average between \$250K – \$400K/mile of pipeline in green field conditions⁴¹ (after adjustment for diameter and length and a 10% addition to account for the different gas medium). We further increase this cost to \$1M/mile to account for two additional issues that are harder to quantify:

- Pipeline materials and maintenance costs are higher with hydrogen due to hydrogen embrittlement concerns and the potential for hydrogen leakage.
- Installing pipelines in an existing city will almost certainly require additional costs associated with road repairs and right of ways after pipes are installed. (Most of the natural gas pipeline data are derived from pipelines over non-urban terrain.)

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⁴¹ Parker, Nathan. "Using Natural Gas Transmission Pipeline Costs to Estimate Hydrogen Pipeline Costs," Technical Report No. UCD-ITS-RR-04-3, Institute of Transportation Studies, University of California, Davis, January 2005.

Figure 42: Remote and Distributed Production: Delivered Cost Comparison

Note that this comparison graph only compares pathways of NG SMR with CCS&D (Central) as a production option - other production options may be less expensive than distributed SMR. However, the broader point is valid: in general, the delivery costs typically outweigh the production cost advantage that remote plants have over distributed plants.

By looking at this analysis we can further reduce the set of pathways considered. Gaseous truck delivery is significantly higher than the other options. It is clear that any pathways that include them will not be the lowest cost. Thus, this delivery option is eliminated from further static demand analysis. Cryo-truck⁴² delivery appears competitive with liquid truck delivery. However, the cryo-truck technology is technically immature and thus its true cost is quite speculative. Additionally, twice as many cryo-truck trailer loads are required than conventional liquid loads. In contrast, liquid trucks are a well-vetted, proven technology. For these reasons, the cryo-truck delivery option is also eliminated from any further static demand analyses. Thus, only remote production pathways with liquid truck or pipeline delivery are considered for the remainder of the static analysis presented here. A further selection between these two delivery options is not appropriate, as the feasibility of installing a pipeline in an established city is not clear.

5.2.1.4 Sensitivity to Dispensing Station Size

Dispensing costs can vary based on station utilization, station size and method of delivery. Since a large static demand has been chosen, utilization cost variances are not explored in this analysis. The effects of station size is initially explored to determine if pathway options can be reduced further before examining dispensing costs associated with different delivery options. For this study we also looked at a 3.0TPD forecourt production plant. These costs

⁴² Cryo-truck stands for Cold Compressed Gas Truck. This delivery option uses cryogenic coolers at the terminal to cool hydrogen gas to 80K. It is a compromise between gaseous and liquid form. More information is available in the front part of this document.

are essentially double those of a 1.5TPD plant. Figure 43 shows cost variation in profited cost of hydrogen at the pump due to station dispensing size. Essentially, dispensing costs vary inversely with station size. However, the hydrogen cost difference observed between a 1.5TPD and 3.0TPD station is negligible⁴³. When one considers that the smaller size will allow more stations in a geographic region, thereby leading to shorter customer driving distances to a station, one would expect 1.5TPD stations to dominate during the transition. Thus only the 1.5TPD dispensing option is carried into the total pathway infrastructure costs comparison.

Dispensing station size is further considered in Section 5.2.2 where a comparison is made between a 100kg/day forecourt production unit operating at high utilization and a larger 1500kg/day unit operating at low utilization.

Figure 43: Pump Profited Cost based on Dispensing Station Size

5.2.1.5 Comparison of Total Pathway Cost

Total pathway infrastructure cost is determined by adding the cost of dispensing (the fourth and final component of a hydrogen pathway) to the previously enumerated costs of production, terminal and delivery in Figure 42. As previously stated, we base the comparison on a NG SMR production plant for both remote and distributed production. (Other remote production options might also yield similar total hydrogen costs.) Recall also that only liquid and pipeline delivery options are chosen for comparison since they have the lowest costs. Figure 44 illustrates the total pathway costs for natural gas SMR production options with these selected delivery and dispensing options.

⁴³ The capital cost scaling between a 1.5TPD and 3.0TPD forecourt production station was nearly linear because a 1.5TPD plant is expected to be close to the largest forecourt unit practical for factory fabrication. Consequently the 3.0TPD production unit is assumed to use two 1.5TPD modules. Storage and dispensing pumps also scale linearly. Thus it is not surprising that the hydrogen cost from both size units turns out to be quite similar.

Figure 44: Total Pathway Pump Prices for Selected Pathways

The Lower Bound 1.5 TPD SMR distributed station is the lowest cost option. The pipeline pathway is \$0.27/kg H₂ higher than the upper bound forecourt and the liquid truck pathway is \$0.92/kg H₂ higher. The other delivery and dispensing options which were discarded previously would result in more costly pathways than the four presented here.

Note that in this a static demand analysis, we assume that hydrogen demand allows the large central facilities to be fully utilized (i.e. operating at their full rated capacity). Should low hydrogen demand lead to low facility utilization, facilities with high capital costs will be disproportionately penalized and the trends described above may not hold true.

This static analysis gives us an initial understanding of hydrogen infrastructure components and their cost contributions, as well as how different options compare to each other. It also quantitatively verifies the common sense notion that lowering delivery costs could help significantly to reduce the cost of hydrogen at the pump. While this analysis shows distributed natural gas SMR stations (with lower bound capital cost projections) being the option of choice, the effects of varied utilization, which are expected to impact the results, have not yet been factored in. These dynamically changing aspects will be explored in later sections of this report.

There are numerous other issues which cannot be explored in this simplistic analysis but will be factors in real world decisions. Consideration needs to be given to issues such as the following:

- The environmental impact of widespread distributed SMR deployment which has no clear cost-effective means of sequestering carbon dioxide;
- The general public's acceptance of installing a pollutant source in the city limits;
- The availability of the required real estate footprint for these stations in an already developed city;
- The required natural gas pipeline upgrades to bring the feedstock to the station; and
- The coverage requirements in the early years which will result in under-utilization.

Prior to reaching the high level of hydrogen demand as is assumed in the static analysis, the demand and utilization at the plant and dispensing site will be much lower. Consequently, one needs to ask: Will the solution be the same at much lower hydrogen demands?

5.2.2 Low Static Demand

In the previous section we found that the 1.5TPD NG SMR forecourts were the most cost effective in periods of high static demand. However, periods of low static demand will occur prior to that so we next evaluate a low demand scenario to see if 100 kg/day forecourt units are more cost effective in that regime. In order to understand how the two distributed plants compete in low utilization situations, we evaluated constant low demand at 10 kg/day, repeat the exercise at 20 kg/day and so on until we reached 1500 kg/day, or complete utilization of a large distributed plant. It is logical to project that during the very early years of low hydrogen demand, the 100kg/day unit would be more cost competitive than the larger 1500kg/day unit due to better utilization of capital (i.e. a higher plant utilization leading to lower capital expense per kg H₂ actually produced). However, there are several competing trends that make the actual outcome different than expectations and difficult to predict.⁴⁴

5.2.2.1 Cost Cross-Over Point

Compared to the 100kg/day units, the larger 1500 kg/day units have higher efficiency and lower capital cost per max hydrogen produced. Consequently, for comparable plant utilization, the larger unit will result in lower hydrogen cost. This decisive cost advantage is clearly shown in Figure 45.

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⁴⁴ This comparison between 100kg/day plants and 1500kg/day plants applies to all production methods, not just to SMR.

Figure 45: Total Cost from Small and Large SMR Distributed Production Plants vs. Utilization⁴⁵

However, when aggregate hydrogen demand is low, particularly in the early days of the transition, production units are likely to be under-utilized. Consequently, for the same hydrogen output, the small distributed unit will have a higher percent utilization than a larger unit and potentially a lower cost. This relationship is shown in Figure 46 where average hydrogen cost is plotted against various levels of constant daily hydrogen production. Thus we see that a cross-over occurs at ~300kg/day: below a hydrogen demand of 300kg/day (at a single location) it is more economical to employ up to three 100kg/day units operating at relatively high utilization rather than a single larger 1500kg/day unit operating at very low utilization.

⁴⁵ FC, NG-SMR,0.1 (AP20) is the same plant as FC, NG-SMR,0.1 but evaluated with a 20 year analysis period versus the 10 year period used on all other options in the graph.

Figure 46: Pump Price of SMR Distributed Plants vs. Hydrogen Produced

The cross-over point of ~300 kg/day is calculated based on a constant hydrogen production level over a 10-year analysis period. However, a ramp-up over time of hydrogen production is expected and is modeled in the baseline analysis. Consequently, the HyPro algorithm analyzes whether the average cost of hydrogen over the entire 10 year analysis period is superior with a small forecourt or a large forecourt unit. Thus the cross-over point cannot be categorically determined by a simple graph but must be based on the 10-year projected hydrogen demand. Rapid increases in hydrogen demand favor large units: slow increases favor the smaller units. It turns out for the baseline scenario (which is based on DOE Hydrogen Demand Scenario 2) that the small forecourt is never selected for build because hydrogen demand ramps up fast enough to always make the larger 1500kg/day unit more economical (averaged over the 10-year analysis period).

5.2.2.2 Circumstances for Selection of 100 kg/day Distributed Plants

The preceding paragraphs describe how station demand and plant utilization play a vital role in determining which scale forecourt unit is able to produce the most economical hydrogen. We observe that the HyPro algorithm computes the 10-year average cost of hydrogen produced and explicitly evaluates the effects of annually varying hydrogen production. Thus, we conclude that 100kg/day stations would be the most economical pathway for hydrogen demands that remain very low (~<300 kg/day) over the entire analysis period or life of the plant.

While the HyPro calculations are always conducted with a 10-year forecourt analysis period, in practice a much shorter analysis period might be rationally considered. Consider the following scenario: It is the early years of the hydrogen transition and hydrogen demand is low. Hopes/Expectations are that demand will increase rapidly but the projections have high uncertainty. The station owner knows that if demand ramps quickly, the “smart” move would be to invest ~\$1M in a large 1500kg/day forecourt production unit rather than in a ~\$300k 100kg/day unit. But he doesn’t have confidence in the demand projections and doesn’t wish to risk more capital than is needed. Consequently, he chooses to buy the smaller unit to limit his capital outlay and still satisfy current hydrogen demand. If and

when hydrogen demand increases he can always upgrade to a larger production unit to achieve lower hydrogen cost. He also knows that he can sell his used 100kg/day unit in the secondary market where it will be moved to the edge of town or to a different city where hydrogen demand is lower and station owners in his exact original situation will purchase it.

The station owner's decision to buy the smaller 100 kg/day unit is rational and follows his risk tolerance, willingness to consider a shorter than 10 year analysis period, and assumption of a secondary market for used production units. None of these factors are currently modeled in the baseline analysis. Consequently, in this case HyPro does not reach the same build decision as the hypothetical station owner.

5.3 Dynamic Demand Studies

HyPro is differentiated from other hydrogen transition models by virtue of its ability to compute discounted cash flows for annually varying plant utilization i.e. hydrogen cost is a function of hydrogen demand. Consequently, HyPro's true value is in studying dynamic demand cases which can then be used as a cross reference to the results of more-easily obtained static demand model results.

5.3.1 General Rules

There are a few simplifying general rules imposed to facilitate dynamic design study calculations:

- Demand exists and is constant or increasing over the analysis period: annual demand does not decline.
- Demand is an independent variable input by the model user and is defined at the beginning of the analysis. The model thus performs calculations and selects pathways with perfect demand foresight.
- Supply must meet or exceed demand.
- The market will allow for all hydrogen to be sold with a 10% rate of return.
- In a year where supply exceeds demand, production is normalized among all existing production options so that all plants have the same utilization.
- Infrastructure build decisions occur once a year.
- Stranding of existing infrastructure components occurs only when new supply costs are below the previous' years strand price.

In addition to these model rules there are technology advancements which are anticipated over the course of the analysis:

- Step change in dispensing technology in 2020:
  - Compressor efficiency⁴⁶ increases from 65% to 80%.
  - The number of purchased compressors decreases from 3 to 1.
  - Compressor cost decreases from \$6,300 to \$4,100/ (kgH₂/hr).
  - Storage tank costs⁴⁷ decrease from \$818/kgH₂ to \$300/kgH₂.
  - Maintenance & repair cost drops from 1.8% to 1.5% of installed capital cost.
  - Output pressure remains⁴⁸ at 5kpsi.
- New delivery option in 2020:
  - A Cold Compressed Gas Truck (CCGT) option carrying 2,100 kgH₂ is added
- Step change in terminal technology in 2020:
  - The number of purchased compressors decreases from 3 to 2.

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⁴⁶ Compressor efficiency is defined as the isentropic efficiency.

⁴⁷ This cost decrease is based on transition for steel storage vessels to carbon fiber wrapped pressure vessels.

⁴⁸ DOE targets project a switch to 10kpsi onboard storage pressure in 2015 and beyond. However, there are no agreed upon capital costs for dispensing stations at those elevated pressures (compressor and storage system). Consequently, our HyPro computations ignore this pressure increase and assume 5kpsi at all time.

- Storage compressors decrease from 2 to 1.
- Storage tank costs decrease from \$818/kgH₂ to \$300/kgH₂.
- Compressor cost factor⁴⁹ decreases from 130% to 80%.
- Urban pipelines are not permitted to be built until 2025. Pipeline installation is labor intensive, widely distributed and disruptive to normal city operations. Thus, intra-city pipeline networks are not expected to be in place until at least 2025.

5.3.2 Los Angeles Baseline Scenario

The Los Angeles, CA metro region⁵⁰ is selected to test the model and explore the build-out sensitivity to infrastructure parameters. Los Angeles lends itself well to this analysis for multiple reasons:

- LA has been designated a “lighthouse city” by DOE and thus a transitional annual ramp-up of hydrogen usage is available on which to base the demand curve.
- The city’s population is large. Consequently, learning curve effects will be discernable.
- California is particularly environmentally conscious. Consequently, it is reasonable to model the most stringent emission regulations.
- The LA topography enables carbon sequestration as well as regional production plants to be situated at the feedstock source.

In order to begin the analysis, several key model input need to be defined:

- City Area
- Hydrogen Demand
- Mandates
- Carbon Taxes
- Credits

City area is based on the H2A value of 1,668 square miles and is held constant throughout the analysis period (i.e. no city sprawl). Hydrogen demand is a function of population, vehicle ownership rate, and percentage penetration of hydrogen vehicles into the automotive light duty vehicle (LDV) market. Making the following assumptions;

- 11.8M people,
- 0.69 vehicles/person,
- 15,000 mi/yr/vehicle,
- No population growth over analysis period, and
- 60.3 MPG_{equivalent} for hydrogen LDV,

we arrive at a hydrogen demand of ~5,300 TPD at full vehicle penetration. Figure 47 displays the projected daily hydrogen demand curve for Los Angeles between the years 2012 and 2050. The projection is based on DOE-supplied scenario analyses (DOE Demand Scenario 2) covering 2010 to 2025 that were then extrapolated to achieve full vehicle penetration by 2050. Market penetration in 2025 is 15%. For the baseline case, renewable hydrogen mandates and carbon emission taxes are not imposed nor are hydrogen production credits granted. This economic case is solely based on the growing demand which must be met and assumes that suppliers will uniformly set prices to achieve a 10% internal rate of return.

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⁴⁹ Compressor cost factor is the percentage multiplier to natural gas compressor cost to obtain hydrogen compressor cost.

⁵⁰ The LA region is defined as Los Angeles, Long Beach and Santa Ana. For simplicity, we refer to this greater LA region as simply LA.

Figure 47: Hydrogen Demand Curve for LA Based on DOE Hydrogen Demand Scenario 2

The likely production plant locations are summarized in Figure 48. City-gate plants would be located along the city limits defined by the red square in the figure. Forecourt plants would be contained within the red lines. Similar to a handful of cities, Los Angeles has some existing overcapacity of hydrogen available from its industrial sector. The industrial area is marked in this figure and the existing supply will be discussed further later on. In addition to production sites, carbon emission disposal sites (not shown in the figure) are assumed to be within 94 miles of Los Angeles⁵¹.

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⁵¹ Benson, Sally M. Comparison of Three Options for Geologic Sequestration of CO₂ – A Case Study for California. LBLL.

Figure 48. Hydrogen Production Plant Locations

During the initial years of hydrogen vehicle introduction, hydrogen demand will be low and very few dispensing stations will be needed to supply the low hydrogen demand. However, additional dispensing stations may have to be initially installed to provide convenient customer access and geographic dispersion. For Los Angeles, we set the minimum number of stations at 40 based on analyses conducted by DTI and the University of California at Davis⁵². Thus at least 40 dispensing stations are built in the first year of the analysis even if demand is low and the stations will be extremely underutilized.

5.3.3 California Specific Rules

Because Californians and their legislature are particularly environmentally conscious, we impose stringent emission rules for the LA baseline scenario. Thus in the analysis described herein, certain constraints are imposed to depict reality:

- Coal gasification plants in California must sequester and dispose of their carbon emissions.
- Coal gasification plants outside of California may choose not to sequester their carbon emissions and may offer their hydrogen for sale in California. (However, such plants will necessarily incur additional hydrogen delivery costs.) This allows for regional coal production options (such as a coal plant located at the mine mouth with long distance pipeline transport of hydrogen) to be included as part of the analysis.

⁵² Nicolas, Mike. "Station Sizing for the California Hydrogen Highway Network", NHA Conference (UC Davis), March 2006. DTI. "FPITT Update on Model Status" Presentation given by Brian James, 27 April 2006.

5.3.4 Feedstock Assumptions

Additional assumptions are made regarding feedstocks. These can be modified to check the model's sensitivity to these assumptions. The assumptions are:

- All feedstocks are readily available in infinite quantities. The model does not correlate consumption quantities to supply prices. However, an offline evaluation may be performed to determine whether the hydrogen infrastructure HyPro selects will strain existing natural resources. If a feedstock shortage is suggested, it can be modeled in HyPro by re-running the analysis with a modified feedstock price or with outright elimination of that feedstock. These investigations are further explained in a later section of this document.
- The cost associated with all feedstocks includes aggregation and delivery of resources to the point of consumption at the hydrogen plant.
- The standard Energy Information Administration (EIA) Annual Energy Outlook (AEO) prices⁵³ are used for most feedstocks. In the case of electricity, natural gas and coal, region-specific data are implemented for more accurate results.
- Feedstock prices vary through the analysis period as prescribed in EIA.

5.4 Projected Infrastructure Build-Out

5.4.1 Feasibility of Lower Bound Forecourt SMR Capital Costs

As shown in previous graphs, the "lower bound" distributed SMR forecourt production option has a decisive cost advantage over all other production pathways. However a key question remains: can the "lower bound" performance parameters be achieved?

The low hydrogen cost of the "lower bound" SMR results primarily from a low installed capital equipment cost⁵⁴, and the key to low installed capital cost is innovation and modularity.

Low capital cost can be achieved either by 1) innovative production method design changes that result in lower temperatures, higher reactor space velocities, or otherwise smaller and cheaper production units, or 2) shifting to mass-produced, factory built units that can achieve low cost through economies of manufacturing.

Innovative reactor and system designs are being pursued by DOE researchers and others with a goal of achieving game-changing low system cost. These systems include tightly thermally integrated configurations, integrated membrane purification systems, micro-channel systems for dramatic component miniaturization, and aqueous phase reformation systems. All of these systems have a common vision of dramatic reduction in system capital cost through novel and improved process chemistry or configuration. While efficiency improvements are certainly to be desired, the already high efficiency achieved with "conventional" steam methane reforming (~70% lower heating value) limits the potential for dramatic improvement. Consequently, the thrust of research has shifted to alternate configurations that are inherently lower capital cost. In this light, the "lower bound" capital costs may be achievable.

Alternately, industry is also pursuing forecourt production units designed specifically for low cost factory manufacture with subsequent transport and very rapid installation at the production site. These companies include: H₂Gen Innovations, HyRadix, HET, and Praxair. This approach fundamentally differs from the conventional paradigm of site-build facilities

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⁵³ Hutzler, Mary J. Annual Energy Outlook 2004 (AEO2004). DOE/EIA-0383 (2004). Energy Information Administration. January 2004.

⁵⁴ The 1500kg/day Forecourt SMR lower bound total production system depreciable capital is \$1.26M versus an upper bound depreciable capital of \$2.2M.

used for large industrial facilities and offers the potential for dramatic capital cost reductions.

The key to success of the modular, factory-build paradigm will be the ability to manufacture significant quantities of units per year so as to achieve manufacturing economies of scale. Some nearly-immediate cost reduction is achievable through modularity of design, but further cost reduction is available through assembly line manufacture which is only feasible at substantial production rates. Consequently, a key to low forecourt unit capital cost will be whether the units are being produced in adequate quantity to achieve low cost. If demand is sufficient, either from existing industrial hydrogen applications, or from automotive applications, then the "lower bound" capital cost estimates can be achieved.

Additionally, forecourt installation costs must also be low to achieve the "lower bound" forecourt cost estimates. The keys to low installation cost are installation simplification and modular station design. As much as possible should be done in the low-cost, factory setting rather than in the comparatively higher cost, site setting. Major components/subsystems should be skid mounted with simplified connections. In the idealized case, installation of the plant can be conducted in a single day "merely" by trucking in the major pieces and lowering them into place. This is truly "optimistic" given real world difficulties but illustrates the concept of rapid, and correspondingly low-cost, on-site installation.

Site preparation is a major cost factor for distributed production. Consequently, to achieve the "lower bound" cost estimates, each production site must not require a start-from-scratch engineering effort. Use of pre-approved forecourt blue-prints would substantially decrease site preparation costs by obviating the upfront engineering cost and by streamlining the approval process. Numerous safety and fire marshal approvals are also necessary for any site. A pre-approved plant layout that shows the system will conform to nationally recognized codes and standards will allow substantial site preparation cost reduction.

Due to these variable and uncertain reasons, baseline assumptions will be run by considering lower bound forecourt SMR units are a reality and a sensitivity study will be done to evaluate the alternative hypothesis that lower bound forecourt SMR costs are not feasible. In the case that it is not feasible, then the upper bound SMR will be available as the distributed SMR option in the 1.5TPD size. The results of the upper bound case are discussed in Section 5.5.2.1.

5.4.2 Baseline Scenario Analysis

In Figure 49 we see that the lower bound forecourt SMR is selected over the entire analysis period. This graph isn't very telling as one does not have any information about pricing nor how this option fares against the other options. For that information Figure 50 has been provided. Here one can see the pump prices of the various low cost options in this baseline case. The lower bound forecourt SMR clearly dominates over the entire analysis period. The existing supply, while inexpensive in production, isn't selected because the terminal investment overwhelms the production cost benefit as shown in Figure 51. Recall in our large static demand analysis that liquid truck and pipelines were the most economical methods of transport. However the demand here is low and early in the transition so pipelines are not available. Thus liquid trucks are the cheapest delivery, but that requires a liquefaction system at the terminal which is electricity intensive. In Los Angeles the cost of electricity is 150% of the national average while natural gas is approximately 80% thus one can see why the existing supply has a hard time competing.

Year	Production Plant	Qty	Year	Production Plant	Qty
2012	FC,NG-SMR,1.5 (LCLB)	40	2033	FC,NG-SMR,1.5 (LCLB)	299
2016	FC,NG-SMR,1.5 (LCLB)	19	2034	FC,NG-SMR,1.5 (LCLB)	293
2017	FC,NG-SMR,1.5 (LCLB)	45	2035	FC,NG-SMR,1.5 (LCLB)	282
2018	FC,NG-SMR,1.5 (LCLB)	56	2036	FC,NG-SMR,1.5 (LCLB)	283
2019	FC,NG-SMR,1.5 (LCLB)	68	2037	FC,NG-SMR,1.5 (LCLB)	286
2020	FC,NG-SMR,1.5 (LCLB)	73	2038	FC,NG-SMR,1.5 (LCLB)	271
2021	FC,NG-SMR,1.5 (LCLB)	78	2039	FC,NG-SMR,1.5 (LCLB)	256
2022	FC,NG-SMR,1.5 (LCLB)	85	2040	FC,NG-SMR,1.5 (LCLB)	236
2023	FC,NG-SMR,1.5 (LCLB)	89	2041	FC,NG-SMR,1.5 (LCLB)	216
2024	FC,NG-SMR,1.5 (LCLB)	107	2042	FC,NG-SMR,1.5 (LCLB)	200
2025	FC,NG-SMR,1.5 (LCLB)	115	2043	FC,NG-SMR,1.5 (LCLB)	185
2026	FC,NG-SMR,1.5 (LCLB)	166	2044	FC,NG-SMR,1.5 (LCLB)	186
2027	FC,NG-SMR,1.5 (LCLB)	192	2045	FC,NG-SMR,1.5 (LCLB)	180
2028	FC,NG-SMR,1.5 (LCLB)	219	2046	FC,NG-SMR,1.5 (LCLB)	218
2029	FC,NG-SMR,1.5 (LCLB)	244	2047	FC,NG-SMR,1.5 (LCLB)	234
2030	FC,NG-SMR,1.5 (LCLB)	266	2048	FC,NG-SMR,1.5 (LCLB)	253
2031	FC,NG-SMR,1.5 (LCLB)	284	2049	FC,NG-SMR,1.5 (LCLB)	272
2032	FC,NG-SMR,1.5 (LCLB)	334	2050	FC,NG-SMR,1.5 (LCLB)	287

Figure 49. Baseline Build - Lower bound SMR Enabled

Figure 50. Price plot for Baseline Scenario

Year	Path Details	\$/kg Hydrogen				Total Cost
		Prod	Term	Del	Disp	
2012	FC,NG-SMR,1.5TPD (Lower Bound)	2.21	0.00	0.00	1.55	3.76
2012	Existing Supply with Liquid Truck Delivery	0.90	2.52	0.18	0.88	4.48

Figure 51. Comparison of Component Costs

5.4.3 Baseline Infrastructure Capital Investment

The hydrogen infrastructure build-out was chosen on the basis of lowest hydrogen pump price (\$/kg). Using the build-out table that is generated by HyPro we can compute the total capital investment of the infrastructure. The capital investment is taken from the discounted cash flow analysis and sums the total depreciable capital costs over the analysis period. Figure 52 shows how this total capital investment is divided among its four components (production, terminals, delivery, and dispensing).

Four key points should be kept in mind when considering this number;

- Capital investment is for only one city (LA): it is not a national summation.
- It corresponds to full penetration (i.e., 100% of vehicles operating on hydrogen);
- The capital investment is made over a 38 year transition period (beginning in 2012 and ending in 2050); and
- Los Angeles covers approximated 33% of California's population and 1% of its land area.

We anticipate that the cost of this infrastructure would be borne primarily by private companies, investors, and consumers with some level of government support to ensure companies had sufficient incentive to get into the markets. To put these numbers in

perspective Figure 53 shows the fiscal budgets for various government departments. Thus one can observe that the total transition cost for Los Angeles (spread out over 38 years) is comparable to the single year budget outlays of some government agencies.

Figure 52. Infrastructure Cost of the Baseline Scenario

Government Department	FY07 Budget (\$Billions)
Energy	\$22.6
Transportation	\$65.7
Defense	\$439.3
Homeland Security	\$35.8
NASA	\$16.3

Figure 53. Government Departmental Budgets

5.4.4 Baseline Emission Projections

With knowledge of the infrastructure build-out pathways that HyPro selects as the most economical, we are also able to project the yearly emissions generated over the entire transition period. These emissions are graphically represented in Figure 54 and represent full lifecycle emissions (well through hydrogen production, excluding delivery and dispensing). To put these numbers into perspective Figure 55 compares selected hydrogen plant emissions with the total gasoline vehicle emissions they are replacing. The cumulative emissions computation is provided in

Appendix G – Cumulative CO2 Emissions Calculations.

Figure 54. GHG Emissions resulting from Baseline Scenario

Figure 55. Resulting Emissions Reduction from Baseline Scenario implementation

5.4.5 Baseline Resource Consumption Projections

With no mandates, carbon taxes or credits, the hydrogen infrastructure will depend on natural gas as the primary feedstock. With one production method, SMR, dominating, it is important to check the feedstock resources required for this infrastructure build-out to confirm that this additional demand can be fulfilled. Natural gas is already a major feedstock in the US for home heating and electricity production. Figure 56 lists recent natural gas annual consumption rates over the most recent 6-year period. National consumption varies by as little as 3% from year to year. California consumption varies by as much as 8% from year to year. However a review of the population over the same period shows an increasing trend with about a 5% increase over the 6-year period.⁵⁵ Since population and consumption do not trend in similar directions⁵⁶ we consider the consumption constant (population growth countered by improved efficiencies and mild weather perhaps).

Trillion Cubic Feet	2001	2002	2003	2004	2005	2006
U.S. Consumption	22.2	23.0	22.3	22.4	22.0	21.7
California	2.5	2.3	2.3	2.4	2.2	2.3

Figure 56. Annual Natural Gas Consumption Rates⁵⁷

⁵⁵ Table 1: Annual Estimates of the Population for the United States, Regions, and States and for Puerto Rico: April 1, 2000 to July 1, 2006 (NST-EST2006-01). Population Division, U.S. Census Bureau. December 22, 2006.

⁵⁶ While population has increased and natural gas consumption decreased over the 6 year period shown, such a trend will not necessarily continue forever.

⁵⁷ Energy Information Administration, Natural Gas Navigator. Consumption. 30 Jan 2008. http://tonto.eia.doe.gov/dnav/ng/ng_cons_sum_a_EPGO_VC0_mmcf_a.htm

The natural gas consumption rates for the hydrogen infrastructure pathways can be computed from the data shown in Figure 57 and with knowledge of plant quantities from the build-out charts. The annual natural gas consumption by the light duty vehicle (LDV) sector is calculated by multiplying the consumption rates by the number of plants online in a given year.

Production Method	Plant Size (TPD)	Lifetime (yrs)	Capacity Factor	Feedstock Efficiency (GJ H ₂ / GJ NG)
Forecourt SMR	1.5	20	70%	0.75
Central SMR	379	40	90%	0.87

Figure 57. Hydrogen Production Plant Data

Knowing the relation between the population of Los Angeles and the total population of California, the natural gas required for the state of California may be extrapolated to realize the baseline infrastructures. Figure 58 projects these requirements. When we compare the LDV NG requirements against the other California natural gas requirements, consumption of natural gas would increase in California about 37% by the time all vehicles have been converted to hydrogen (in the baseline scenario). While this is a significant amount, it occurs over 38 years and may be dwarfed by additional natural gas consumption from other factors such as population growth. World supplies of natural gas are large (see Figure 59) and this increase in natural gas consumption will not deplete global supplies. However, a 37% increase would no doubt create US supply difficulties as most natural gas is already imported into the US and the current trans-shipment network is near capacity. This analysis could be repeated for any of the feedstocks to determine if a shortage would occur due to the hydrogen economy. More detailed calculations are available in Appendix H - Feedstock Consumption Check.

Figure 58. NG Consumption Rates in CA

Region	Natural Gas (Trillion Cubic Feet)
North America	276.9
United States	204.4
Central & South America	240.7
Europe	180.3
Eurasia	2,014.8
Middle East	2,566.0
Africa	484.4
Asia & Oceania	419.4
World Total	6,182.7

Figure 59. World Proven Reserves⁵⁸

5.5 Sensitivities and Comparisons

The baseline case indicates steam methane reforming technology dominates the transition to hydrogen. However, focusing on just a single technology is usually not an economically prudent decision. Therefore, this section discusses the results of several sensitivity analyses performed on some of the key input assumptions to investigate whether the baseline build-out is robust or changes dramatically with minor assumption alterations. The

⁵⁸ PennWell Corporation, Oil & Gas Journal, Vol. 104.47 (December 18, 2006). Oil includes crude oil and condensate. Data for the United States are from the Energy Information Administration, U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves, 2005 Annual Report, DOE/EIA-0216(2005) (November 2006). Oil & Gas Journal's oil reserve estimate for Canada includes 5.2 billion barrels of conventional crude oil and condensate reserves and 174.0 billion barrels of oil sands reserves.

key assumptions investigated here are; demand, pipeline cost and availability, real estate availability, feedstock supply, affects of learning on FC SMR, and other low-cost production options. External factors such as government policy can influence the hydrogen transition as well but that topic is explored in a separate section.

5.5.1 Demand

A logical first choice parameter to vary is the demand, since the build is a response to the change in demand. In the static section of this report we presented pricing for both high and low demand. Likewise here we look at two additional DOE Demand Scenarios. DOE Scenario 1 achieves 6.6% of demand in 10 years and full penetration by 2050. As you can see from Figure 61, this lower transition demand doesn't impact the build. DOE Scenario 3 achieves 15.53% of demand in 12 years and again full penetration by 2050. Even this more accelerated demand does not foster remote plants to be selected. Both of these demand scenarios were considered possible by the DOE. A faster transition is probably not realistic, thus these studies indicate that demand is not a primary factor, at least not in a city the size of Los Angeles.

Figure 60. Demand Scenario 1 Sensitivity

Figure 61. Demand Scenario 3 Sensitivity

5.5.2 Other Low cost Production methods

Our first sensitivity showed that our solution did not vary with demand. In this set of studies other production options are evaluated to determine if they have an effect on the build out schedule.

5.5.2.1 Upper bound SMR Forecourt Capital Costs

As mentioned in the baseline case analysis there is some skepticism about whether the capital costs of the lower bound forecourt SMR option are obtainable. Thus one removes the lower bound distributed SMR option from the database under the assumption that meeting the cost target is **not** feasible. In this study, the upper bound forecourt SMR option is the only available distributed SMR option in the 1.5TPD size. The resulting build-out is shown in Figure 62.

Figure 62. Baseline Analysis with Upper Bound SMR Costs

The first year of the analysis period, the existing hydrogen surplus is the most economical option⁵⁹. Because that supply is larger than the demand through 2016, no other pathways are selected until 2017 (outlined boxes in the figure represent supply while the 'x' and column height represent demand). Once supply is exceeded and demand is sufficiently large to fully utilize the minimum number of dispensing stations, the upper bound forecourt SMR costs decrease dramatically and become the pathway of choice. It is not until 2030 that a large central plant is able to compete with the upper bound forecourt SMR. Figure 63 graphically demonstrates total cost of several pathways. The cost with return of central natural gas SMR plants (with pipeline delivery) doesn't drop below that of upper bound distributed SMR until 2029. Thus, the transition from distributed reforming to central production begins in 2030.

There are several ways to explain for why remote plants are not selected until 18 years into the transition. First, during the early years of the transition while demand is low, large central plants remain at low utilization longer and thus do not employ their capital as efficiently as smaller distributed plant⁶⁰. A typical large central plant has a production capacity of 300 – 400 TPD, suggesting that such a large plant will not be selected until demand is at least that amount. So for central plants to be competitive with distributed plants, they need to quickly achieve high utilization which leads to the next point.

Ramping to high utilization quickly requires that the incremental demand from one year to the next be of comparable size as a central plant. While the demand in our study achieves central plant volumes in 2021 (see Figure 47), the growth rate from the previous year is not

⁵⁹ Section 5.5.2.2 has additional details about the existing hydrogen supply pathway option.

⁶⁰ While large central production plants have a lower capital cost per peak H₂ kg produced, the lower plant utilization in the first years of operation more than offsets this advantage.

sufficient to fully utilize a large plant. Increases of larger than 200 TPD over the previous year's demand don't begin to occur until 2027. The incremental demand increase can happen by design of the input demand curve or by stranding. In the case of stranding the central plant production costs are less than the variable costs of what has already been built thereby displacing or stranding it.

Third, central plant pathways require terminal and delivery components which a distributed option does not. Recall from our baseline assumptions pipelines are not available until 2025⁶¹ so remote plants with pipeline delivery cannot be chosen prior to 2025. Additionally, the next lowest delivery option, liquid trucks are more costly than the distributed options as proven previously in the high static demand analysis.

Lastly, like production, pipelines need to be fully utilized to be cost effective. From the earlier high static demand analysis, pipeline delivery is the most cost effective delivery method but in a dynamic demand situation, the hydrogen demand must be both large and increasing at a high rate: large to make pipelines cost effective and increasing at a high rate to allow remote-with-pipeline pathways to reach full utilization early in their lifetimes. Factoring in the expected utilization, the large central plant is not selected until 2030.

Figure 63: Scenario 2 Build-Out with "Upper Bound" Forecourt SMR

Since eliminating the lower bound SMR forecourt from the production options changes the build out, the emissions of the new build and the total infrastructure costs were computed. Those are shown in Figure 64 & Figure 65 respectively. While the cost of the infrastructure is larger, the emissions of the alternative build are slightly less.

⁶¹ The timing of pipeline availability is addressed in a separate study.

Figure 64. GHG Emissions for Alternative Case with Upper Bound SMR

Figure 65. Infrastructure Costs, with an Upper Bound Distributed SMR

5.5.2.2 Impact of Existing Hydrogen Supplies on the Transportation Hydrogen Build-Out

Los Angeles is a major metropolitan region that is likely to be one of the first hydrogen transition areas due to its air pollution problems, high population density, and its citizens' environmental priorities. Additionally, the greater LA region has an unusual number of petrochemical refiners that can potentially supply surplus hydrogen to the LDV sector during the early transition. Consequently, we use LA as a test bed to answer three questions:

- How much surplus hydrogen from existing plants is available for transportation?
- How long into the transition will this supply be a benefit?
- How much does it cost and is it competitive?

Hydrogen production facilities existing today serve the industrial sector, which is dominated by the petrochemical industry, and to a much lesser extent the merchant gas industry. While plants strive to operate at 90%+ of capacity, real world market fluctuations cause many of these plants to operate at diminished production and thus have additional capacity that could be tapped to assist in the hydrogen fuel transition. After lengthy discussions with existing facility operators, it was estimated that approximately 5% of the production capacity at each plant is available for sale to the transportation sector as "surplus" hydrogen. It is further estimated that this hydrogen could be sold at a variable cost of ~ \$0.80/kg H₂. (This is not the total cost to the consumer because hydrogen still has to be transported to the dispensing station.)

Based on the quantity of existing production in the Los Angeles area, this analysis assumes 80 TPD of EXISTING Hydrogen supply (see Figure 66). The majority of this capacity is in gaseous form since the base load production is destined for gasoline refineries. Los Angeles is unique in that it has a rather large supply of existing hydrogen that it can potentially tap. Most cities do not have this large and reliable existing source and will have to build new production infrastructure from the beginning.

I – Ontario plant is too far northeast of Los Angeles to be shown here.

Code	Plant Name ⁶²	Year Built	Location (within CA)	Type of Hydrogen	Plant capacity (TPD)
A	ExxonMobil	1988	Torrance	Gaseous	312
B	Chevron Products Co	1976	El Segundo	Gaseous	285
C	ARCO Products Co	1996	Carson	Gaseous	248
D	Air Products and Chemicals; Inc.	2000	Carson	Gaseous	236
E	Air Products and Chemicals; Inc.	1996	Wilmington	Gaseous	189
F	Air Products and Chemicals; Inc.	1998	Wilmington	Gaseous	189
G	Tosco Corp	1992	Wilmington	Gaseous	182
H	Equilon Enterprise, LLC	1990	Wilmington	Gaseous	35
I	Praxair; Inc.	1962	Ontario	Liquid	20
	Existing H ₂ Production				1,676
	5% of Existing Capacity				~80

Figure 66: Location and Quantity of Existing Hydrogen in Greater Los Angeles Area

Separate studies show that at 80 TPD, truck transportation of hydrogen is most economical in liquid form. An amount of \$0.10/kg H₂ is added to the price of production in order to pipe

⁶² Original data taken from California Energy Commission. The reduced form shown here was provided by Keith Parks of NREL.

the various supplies (primarily located in the Harbor area) to a central terminal facility⁶³. The terminal includes a liquefier, bulk storage for outages and supply fluctuations, and trucking bays. During the early years of the transition when demand is low, this method of using existing excess production is cost effective when coupled with liquid truck delivery. Since automakers are designing vehicles with a gaseous hydrogen fuel in mind, the liquid form will have to be converted to gaseous at the dispensing station. This will require that dispensing stations be equipped with both liquid and gaseous storage, pumps, evaporators, and compressors. In the pathways where existing hydrogen is used⁶⁴, terminal & dispensing costs are variable and high since both are operating at low utilization (until demand exceeds the capacity of the terminal or initial 40 stations), while production costs are fixed since we are purchasing a surplus amount on a large steady base of hydrogen production.

In our baseline scenario the presence of existing hydrogen has no effect on the build out because of the low cost of the lower bound forecourt SMR. The expected profited cost of the hydrogen for existing hydrogen with liquid truck delivery is \$4.48/kg H₂ which from Figure 68 is \$0.14/kg H₂ less than the upper bound SMR option. While this is still costly in comparison to the lower bound SMR option, should that option not become a reality, Figure 68 shows Existing Hydrogen to have a market niche from 2012 – 2016. In 2017 once demand outgrows supply, the upper bound SMRs, being the next cheapest, are selected for build.

So, why would Los Angeles choose a limited capacity option rather than build upper bound distribution SMR units from day one? We expect that the existing gaseous hydrogen supply in LA would not be used unless:

- Performance assumptions of the Upper bound distributed SMR unit are not achievable.
- Dispensing sites are located very close to the existing hydrogen production facility or to existing pipeline making “tapping-in” very convenient and inexpensive.
- The existing hydrogen supply is already being liquefied making it very easy to dispatch an LH2 delivery truck from the plant to a dispensing station.

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⁶³ Hydrogen liquefiers are capital intensive and benefit greatly from economics of scale. Consequently we have postulated multiple gaseous production plants pooling their excess gaseous hydrogen via a pipeline network in order to make use of a single, 80TPD liquefier. An amount of \$0.10/kg H₂ is estimated for the creation of this pipeline.

⁶⁴ Recall that the Lower Bound Forecourt SMR is always selected over hydrogen from the existing supply. Thus existing hydrogen is only selected when Lower Bound Forecourt SMR is not available.

Figure 67: Existing Hydrogen Cost Compared to 'Upper Bound' Forecourt SMR Hydrogen Cost

Figure 68. Los Angeles Build-Out with Upper Bound SMR

5.5.2.3 Hydrogen from Municipal Solid Waste (MSW)

While all of the conventional production options are available in the baseline model, from time to time other methods of producing hydrogen show potential. One such production option is hydrogen from municipal solid waste (MSW). The U.S. Environmental Protection Agency (EPA) estimates that 54% of solid waste is disposed of in landfills⁶⁵, which is approximately 132 million tons per year. The number of landfills has decreased by 80% over the last 17 years⁶⁵, although total capacity has not. This means that landfills are growing larger in locations further away from the cities they support. With the national population expected to grow by 38% by 2050⁶⁶, MSW appears to be a constant feedstock that could be used assuming the technology is there for its conversion to hydrogen.

We have assumed a 150 TPD MSW-to-hydrogen plant capital cost of \$126M (total depreciable cost) and a 65% efficiency based on information from an unnamed industrial company. The technology for hydrogen conversion was not specified but is assumed to be either a conventional or plasma gasification process.

The final piece of this is establishing the MSW feedstock costs. The Solid Waste Digest publishes a state-by-state chart of tipping fees paid to landfills by haulers. The costs are far from uniform, varying between \$18/ton - \$73/ton in 2004⁶⁷. Thus our sensitivity took on two forms; feedstock as a fixed revenue source at \$35/ton, and feedstock as a variable cost varying from revenue source at \$35/ton to variable cost at \$35/ton; the thought being that as the transition begins, production plants can, by their proximity to the city, siphon off some of the haulers that would typically go to a regional landfill to dispose of their load. However as hydrogen demand increases, so does the demand for the MSW feedstock and thus plants will most likely need to pay for the resource in the future.

Figure 69 through Figure 71 show the results of introducing this MSW-to-hydrogen production method and its different feedstock costs scenarios to the baseline study. Figure 69 shows that when MSW is not only the feedstock but also a revenue source, then it wins over the lower bound forecourt SMR in 2028. At this point there is sufficient demand for the 150 TPD plant to operate at a high utilization for the greater portion of the analysis period and thus be the most economical pathway. Figure 70 shows that when the feedstock is varied from revenue source to variable cost (+/- \$35/ton) the year in which the MSW pathway is selected doesn't change. However at the point where the feedstock revenues are less than \$7.30/ton, MSW is no longer the most economical option and lower bound forecourt SMRs reclaim the hydrogen transition. Should the lower bound forecourt SMRs not be obtainable, then the other lowest cost options in Figure 71 will be competitive. The solution in this case would look like upper bound forecourt SMRs until pipelines became available. The MSW plants would come online as soon as pipelines were available and would dominate the market until 2040 when central SMR plants undercut the MSW's pump price. In that year the MSW feedstock is at a variable cost of \$2.24/ton.

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⁶⁵ <http://www.epa.gov/garbage/facts.htm>.

⁶⁶ <http://www.census.gov/compendia/statab/tables/08s0010.pdf> & <http://www.census.gov>.

⁶⁷ Solid Waste Digest, June 2004, Volume 14, Number 6.

Figure 69. Build out resulting from an MSW option with feedstock revenue

Figure 70. Build out resulting from an MSW option with a varying feedstock price

Figure 71. Price plot where MSW has varying feedstock price

5.5.3 Verifying Pipeline Parameters

5.5.3.1 Pipeline Availability

In the baseline analysis we make the assumption that pipelines are not available until 2025, based on the amount of disruption that would be caused by installing them. We tested this parameter by removing the constraint and allowing pipelines to be available on the first day of the analysis. The build-out did not change. From the price plot in Figure 72 we see that the cost of the cheapest pipeline option never drops below that of the Lower Bound forecourt SMR.

Figure 72. Price plot with Pipelines available in 2012.

5.5.3.2 Pipeline Capital Cost

The static analysis showed that pipelines when fully utilized are the lowest cost deliverer of hydrogen. In both the static analysis and in our baseline scenario the installed cost of pipeline within the city limits is \$1M/mile for the reasons enumerated in Section 5.2. Using the EIA AEO costs for natural gas pipeline and applying those to hydrogen pipelines, the cost per mile installed is substantially lower than the baseline value as shown in Figure 73. Since the delivery component is approximately 1/5 of the pathway cost and these costs are being reduced by more than 50%, one would expect the pipeline capital cost to influence the build-out. However, as Figure 74 shows, this is simply not enough of a decrease in cost to make pipeline delivery competitive.

Depreciable Component	Capital Cost Value	Units
Overhead, Pipeline Material	\$35,000.00	[\$] (ea.)
Overhead, Miscellaneous	\$95,000.00	[\$] (ea.)
Overhead, Labor	\$185,000.00	[\$] (ea.)
Overhead, ROW	\$40,000.00	[\$] (ea.)
Overhead, Pipeline TOTAL	\$355,000.00	[\$] (ea.)
Pipeline Cost Factor	110%	[% of Pipeline Cost]
Unit Cost, Pipeline Material	\$31,298.82	[\$/mi]
Unit Cost, Miscellaneous	\$20,341.71	[\$/mi]
Unit Cost, Labor	\$190,705.77	[\$/mi]
Unit Cost, ROW	\$33,608.98	[\$/mi]
Unit Cost, Pipeline TOTAL	\$275,955.28	[\$/mi]

Figure 73. Pipeline Costs using EIA AEO Estimates

Figure 74. Price plot of Distributed vs. Remote Production Options

As mentioned previously, pipeline delivery cost is sensitive to utilization and demand. Since pipelines cannot reach high utilization until there is sufficient demand, changes in their availability and costs are not sufficient to accelerate their introduction. Thus, these are not primary factors in determining the hydrogen build out.

5.5.4 Competition for Natural Gas Resources

The HyPro model has no rules concerning availability of natural gas: it assumes that there is an endless supply. In reality, that is not the case and as more industries grow, the LDV sector will have to compete for those resources. That competition will manifest itself in increased prices of the feedstock. To test the build-out's sensitivity to natural gas we kept the upward trend the same but double the price of the feedstock. The corresponding build-out is shown in Figure 75. The next favorable resource is coal and this is when natural gas prices reach \$14.22/GJ. To the hydrogen consumer, the result is a higher pump price for hydrogen. Comparing Figure 50 and Figure 76, one can see that in 2050 at full penetration hydrogen costs approximately \$0.30/kg H_2 higher than in the baseline scenario.

Figure 75. Build-Out when Natural Gas has an increased cost due to resource competition.

Figure 76. Price plot for Natural Gas Price Sensitivity

5.5.5 Land Availability within City Limits

The HyPro model has no explicit rules concerning land availability. Like feedstocks, HyPro has infinite land available on which to locate these plants. Thus the land area required in the baseline scenario by forecourt production stations must be determined and assessed as to whether it represents a reasonable amount of the city's area. Additionally, the individual station land requirements need to be compared with those of gasoline stations to ensure that sufficient land is available on individual plots for the placement of these stations. From the build-out table, the number of units built at maximum demand may be determined. Within the input database, the required area for each component in the pathway has been recorded. Since concern is mainly within the city limits, this computation is limited to dispensing stations and forecourt production.

Dispensing Stations	Qty in 2050	ft2/ Station
H2 Production		936
H2 Dispensing		5808
Remainder of Station(footnote)		10,875
Total	5055	17,619
Typical Gasoline Station		14,300

Figure 77. Forecourt Stations in Los Angeles

Based on the information in Figure 77 for the baseline build-out, the amount of real estate required, 1.22 mi², is negligible compared to the city area of 1668 mi². However, the square footage of an individual station is 1.23 times larger than a typical gasoline station⁶⁸. This creates a problem because Los Angeles is a highly populated region and thus a plot of land, appropriately zoned for a station of this size and strategically located within high traffic areas, is difficult to find. One approach postulated by the DOE⁶⁹ is to locate stations in large retail parking lots (i.e. the Wal-Mart solution). While station footprint is acknowledged as a problem, it is not one which can be solved in this analysis. What one can represent in this model is a shortage of land by use of a higher rental rate. The resulting price plot shown in Figure 78 indicates that doubling rental rates to \$1.00/ft²/month will have little impact on the pump price of hydrogen or the rate at which forecourt production stations are built. However the issue is raised and should be addressed by appropriate DOE research efforts.

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⁶⁸ Gasoline stations vary in size considerable. Consequently, we define a "typical" gasoline station as having 8 dual hose dispensers and a station footprint of 14,300 ft² based on work done by TIAX.

⁶⁹ Personal communication with Sig Gronich, US DOE Hydrogen Project Office.

Figure 78. Price plot for Land Availability Sensitivity

5.5.6 Affects of Modeling Learning

The primary source of data for the HyPro database was H2A. In most of the production cases, H2A has developed costs for 2005, 2015 and 2030. Typically the costs of production decrease in the future. That decrease is based on several assumptions including technology improvements and units produced. While technology improvements may indeed occur with several components, such as pressure vessels and compressors, due to their usage in other industries, the number of production units built is completely dependent on the demand for hydrogen. There is no demand if there is no supply and there is no supply if there is no demand. This is the classic chicken and egg problem. Since our model is capable of quantifying the number of units built every year and the forecourt 1.5 TPD SMR units were the preferred solution, we chose to model learning directly rather than implicitly for that production option. The baseline results shown previously take into account the effects of learning both from Los Angeles and from a hypothetical exterior build (other US lighthouse cities). In order to quantify how different this is to the H2A implicit assumption of pricing for the 500th unit on day one and 1000th unit in 2015, we ran a simulation with both options. The forecourt SMR's with H2A cost parameters were selected over the entire transition. However, looking at the price plot in Figure 79 one sees that the pump price of both options is fairly similar. This leads us to believe that although our model is more accurate, the results don't vary significantly enough for the build out to be sensitive to this parameter.

Figure 79. Price plot showing forecourt SMRs with different cost models

The third price line found on the plot is an upper bound cost estimate for the forecourt 1.5 TPD SMR unit. This option is discussed in Section 5.5.2.1.

5.6 Financial Incentives

While some financial incentives are currently in place, they mainly focus on hydrogen vehicles and fuel cells. Financial incentives for hydrogen generally seem to focus more on the end-point; either use of hydrogen-fueled vehicles or use of hydrogen in fuel cells for electricity generation. There are varying incentives for private consumer use of vehicles or public fleets. Our main interest is in exploring the affect of policies that can promote and shape the hydrogen production infrastructure. However, few specific incentives for hydrogen production, HyPro's main focus, are found. Electricity provided by a fuel cell is also considered as a category of clean energy and provided incentives. Many of the incentives applied to renewable electricity generation, could be applied to hydrogen systems, including production, storage, delivery, and dispensing stations. Consequently, policies that are used within the renewable electricity generation sector form an appropriate source of ideas. The incentives listed below are those currently available for renewable electricity generation.

1. Property Tax Incentives

These incentives could be applied to components of the production facility or the refueling station, by way of exemptions, exclusions, and credits. The added value of the component in consideration would be deducted from its valuation for tax purposes.

2. Sales Tax Incentives

These typically provide exemption from the state sales tax for the cost of equipment.

3. Production Incentives

Production incentives are typically used for renewable electricity generation (\$/kWh incentive) or renewable fuels (\$/gallon incentive) – could be applied to hydrogen production too. Incentive is based on performance, rather than capital investment. So an incentive based on the dollar per amount of hydrogen produced, or even the amount/percent coming from renewable resources, could be used.

4. Accelerated Depreciation

The federal government currently provides five year depreciation for renewables, which could be expanded to hydrogen production or hydrogen vehicles. The effect would be to transfer profit from later periods to earlier periods, since all tax benefits are claimed in the first five years.

5. Loan Guarantees

The federal government provides up to \$4 billion in loan guarantees for purchase of hydrogen generation equipment or hydrogen vehicles.⁷⁰ Probably already covered by EPA Title XVII, which applies to technologies that “avoid, reduce, or sequester air pollutants or anthropogenic emissions of greenhouse gases; employ new or significantly improved technologies as compared to commercial technologies in service in the United States at the time the guarantee is issued,” and have a “reasonable prospect of repayment of the principal and interest on the obligation by the borrower.”

6. Grant Programs

A state or federal grant of X dollars could be applied to the overall cost or the capital cost of the production facility or any other infrastructure component. Typical state grants applied to renewable energy systems range from \$500 – 1 million.

7. Manufacturing Incentives

The individual components used in a hydrogen production, storage, delivery and dispensing infrastructure are key to the overall system cost. For example, high electrolyzer costs increase the cost of producing hydrogen via electrolysis. Therefore, if these individual components are manufactured at higher-volume, costs will eventually come down. Industry recruitment incentives are in place for clean energy systems, with the goal being to attract manufacturers to a specific state or city via financial incentives such as tax credits, grants or commitment to purchase the product manufactured. This concept could also be applied to potential manufacturers of components of the hydrogen infrastructure, such as electrolyzers, storage tanks, etc.

8. Rebate Programs

Typical rebates for renewable energy systems range from \$300 – 1 million. Rebates could be structured for hydrogen production systems too and would be based on system capacity.

9. Carbon Tax

The amount of carbon emissions from a production pathway would be taxed and this in turn would determine the hydrogen price difference between the pathways, placing some technologies at an advantage and some at a disadvantage.

10. Cap-and-Trade Programs

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⁷⁰ <http://www.lgprogram.energy.gov/titlexvii.pdf>, <http://www.lgprogram.energy.gov/>

California has set limits on carbon dioxide emissions and legislation has been put into place to provide a cap-and-trade system to deal with these emissions. This system would once again differentiate between green-based and fossil-based hydrogen production pathways.

11. Government Subsidies Based on Floor Price

There are examples of the government subsidizing a technology by providing a base floor price. This concept could potentially be applied to hydrogen production too, where the government would be assisting by subsidizing the difference between the market price and the producer's price for hydrogen.

These policies can be described in economic terms within the HyPro simulation as three types of policies: mandates, taxes and cost credits. *Mandates* are government-imposed policies that require certain actions to be taken or prohibit certain actions from being taken. An example of this is a California policy which mandates that a certain percentage of electricity generation for the state be from renewable sources. *Taxes* are financial consequences to behaviors that are considered not favorable to society as a whole. The best example of this is a carbon tax levied on polluters, thereby reducing a plant's financial gains and encouraging carbon sequestration. *Cost credits* are government provided funds to assist an individual company in entering a capital intensive market. Grant and rebate programs are examples of capital cost credit policies in execution.

5.6.1 Mandates

HyPro doesn't currently have the functionality to dictate the percentage of hydrogen production from renewable resources in a given year. Instead, different years within the analysis period are chosen at which non-desirable options are no longer available. Two mandates are tested, a renewable feedstocks mandate and a carbon sequestration mandate. To understand the sensitivity to these mandates, implementation year (2020, 2032 and 2040) was varied parametrically. The costs and total emissions of the resulting build-outs are summarized in Figure 80. As suspected, mandates cause the infrastructure investment costs to increase, reflected in the pump price of hydrogen. In all cases, the mandates refer to new plant builds and existing facilities are "grandfathered" in.

Mandate Year	Use of Renewable Feedstocks			Carbon Sequestration		
	Capital Cost (\$B)	GHG Emissions (MTons) ⁷¹	2050 Pump Price (\$/kg H ₂)	Capital Cost (\$B)	GHG Emissions (MTons) ⁷¹	2050 Pump Price (\$/kg H ₂)
BSL	12.5	339.0	\$2.60	12.5	339.0	\$2.60
2020	14.1	22.9	\$3.85	25.1	122.7	\$2.90
2032	13.7	180.3	\$3.85	23.4	241.1	\$2.90
2040	13.1	297.6	\$3.85	18.1	314.8	\$2.90

Figure 80. Effectiveness of Mandates

While Figure 80 provides the total amount of emissions, a review of the emissions emitted over the analysis period provides more tangible perspective on these values. The figures below show the emissions resulting from each hydrogen production facility when put into operation. Figure 81 compares the emissions resulting from the renewable mandates in each of the three implementation years with the emissions of the baseline scenario. Figure 82 compares the emissions of all three CCSD mandates with the baseline emissions. The

⁷¹ Greenhouse Gas (GHG) Emissions listed here are the cumulative amount resulting from hydrogen production facilities built to support LDV hydrogen demand in the years 2012 through 2050.

effects are significant and should be considered when reviewing policies and capital outlays required. The plants that put out these emissions are discussed later in this section.

Figure 81. Emissions profile from Renewable Mandates

Figure 82. Emissions profile from CCSD Mandates

5.6.1.1 Carbon Sequestration Mandates

A carbon sequestration mandate would allow only low carbon emitting clean alternatives to traditional fossil fuel production plants to be built. Renewable plants are also permitted because they are non-carbon emitting facilities. For Los Angeles, we have already established a baseline scenario requirement that all coal plants within the state boundaries have sequestration. This mandate expands on that by requiring regional facilities, as well as natural gas SMR plants, to have carbon sequestration. Distributed SMR plants, the winning pathway in the baseline case, are eliminated from consideration as no small scale sequestration method is considered practical.

The resulting builds from this mandate requirement in different years are shown in Figure 83 through Figure 85. One can see that the sequestering options are chosen (in all but one case), confirming that it is less costly in terms of hydrogen pump price to sequester than to produce hydrogen from a renewable source. Distributed Ethanol is selected temporarily in the case of the 2020 CCSD Mandate because pipelines are not available until 2025. As soon as pipelines become available the build switches to a central SMR plant with sequestration. Thus a carbon sequestration mandate alone is not adequate for renewables plants to flourish: an industry mandate or other policy is necessary.

Figure 83. Infrastructure resulting from 2020 CCSD Mandate

Figure 84. Infrastructure resulting from 2032 CCSD Mandate

Figure 85. Infrastructure resulting from 2040 CCSD Mandate

5.6.1.2 Renewable Feedstock Mandates

The infrastructure build-outs resulting from a renewable feedstock mandate postulated in different years are shown in Figure 86 through Figure 88. In all case the results are the same; FC, SMR (Lower Bound) transitioning over to Distributed Ethanol. From the Figure 80, it seems that the greenhouse gas emissions benefit more than outweighs the additional expenditures required for a renewable build-out. However this information is misleading because in the case of an ethanol-to-hydrogen production facility the cost of feedstock is a dominant parameter that is not captured in the capital costs. It is however captured in the pump price. Notice that the difference in hydrogen price to consumers is more than \$1.00/kg H₂ higher than the baseline solution. The next lowest cost renewable are production plants that use nuclear feedstock, however those are so large in capacity that it is difficult for them to compete when demand increments are not substantial. The price plot in Figure 89 shows how the pump price of the options compare when all the demand for a given year is satisfied completely by a given production option.

Figure 86. Infrastructure Resulting from 2020 Renewable Mandate

Figure 87. Infrastructure Resulting from 2032 Renewable Mandate

Figure 88. Infrastructure Resulting from 2040 Renewable Mandate

Figure 89. Pump Price of Renewable Options

5.6.2 Carbon Tax

In electricity generation SO_2 and NO_x emission reductions are being addressed via a cap-and-trade system. Thus it is plausible that this method would be extended to hydrogen generation as well. While we don't have the capability to mimic a cap-and-trade system in HyPro, we can quantify the emissions for each production option and tax the emissions. While not the same as a cap-and-trade system, this approach will help determine the cost impact of emissions and emissions control (sequestration systems).

The main emission of concern is carbon dioxide. There are currently no taxes on this emission in other industries so it is difficult to gauge what an appropriate tax might be. Based on industry discussions, we estimate that \$25/ton CO_2 is the approximate level of carbon taxes being discussed and matches the current CO_2 trading cost in Europe. The resulting infrastructure build-out is shown in Figure 90. Since the build-out is unchanged from the baseline, we can infer that the capital cost of sequestration equipment outweighs the tax penalty paid by forecourt SMR (1.5 TPD) stations for carbon emissions. The premiums for emitting carbon and sequestering it for SMR and Coal plants can be inferred from the data in Figure 91. The emissions associated with each option and the impact on pump price is also noted. Figure 92 shows how the pump price moves with carbon mitigation policies for the three lowest cost production methods; FC-SMR, Central SMR and Central Coal. In the case of Central Coal (lower left-hand frame) it is cheaper to pay the additional capital required for sequestration equipment and pay a tax on the remaining emissions than it is to simply pay a tax on the total unsequestered emissions. This is not so for the Central SMR case shown in the upper right-hand frame of Figure 92. In that frame we see that it is cheaper to pay a tax on the total unsequestered emissions than it is to pay the additional capital required for sequestration equipment. Figure 91 shows emissions from a Central SMR plant are less than half of those of a Central Coal plant. So the cost

benefit of sequestering emissions versus pay a carbon tax is dependent on the level of emission produced and that level is specific to each production plant, its capital costs and its capacity. Prior to that emissions level, the producer does not have an incentive to produce hydrogen by a cleaner method. This emissions level will vary with the amount of the tax and the total depreciable capital required for the production facility.

The data in Figure 91 helps us determine the carbon tax required for FC, NG SMR and Central SMR+ CCSD options to result in the same pump price. The amount is important because it indicates the minimum value (in the form of a carbon tax) that the market places on carbon sequestering or renewable fuel production plants. Setting the pump price of each option equal to each other (where pump price is the zero tax price plus the emissions multiplied by the tax) and solving for the tax value we conclude that in 2025 a carbon tax of at least \$132/ton CO₂ is needed for the pump price from a Central SMR+CCSD plant to be equivalent to that of the FC, NG-SMR.

Figure 90. Los Angeles Build-out with \$25 Carbon Tax is assessed

Production Method	2025 Emissions (kg CO ₂ /kg H ₂)	Pump Price (\$/ kg H ₂)		
		2025	2030	2050
FC, NG-SMR (\$25 Carbon Tax)	9.5	\$ 2.58	\$ 2.63	\$ 2.83
FC, NG-SMR (Zero Tax)	9.5	\$ 2.47	\$ 2.54	\$ 2.77
		2025	2030	2050
Central SMR + CCSD (\$25 Carbon Tax)	2.3	\$ 3.48	\$ 3.20	\$ 3.17

Production Method	2025 Emissions (kg CO ₂ /kg H ₂)	Pump Price (\$/ kg H ₂)		
		2025	2030	2050
Central SMR (\$25 Carbon Tax)	8.7	\$ 3.25	\$ 2.97	\$ 2.93
Central SMR (Zero Tax)	8.7	\$ 3.03	\$ 2.75	\$ 2.72
		2025	2030	2050
Central Coal + CCSD (\$25 Carbon Tax)	3.5	\$ 3.55	\$ 3.22	\$ 2.99
Central Coal (\$25 Carbon Tax)	20.3	\$ 3.63	\$ 3.30	\$ 3.07
Central Coal (Zero Tax)	20.3	\$ 3.12	\$ 2.79	\$ 2.56

Figure 91. Carbon Tax Impact on Pump Price

Figure 92. Carbon Tax Implications on Pump Price

Figure 93. 4th Frame of Figure 92 enlarged

5.6.3 Capital Cost Credits

Capital cost credits have been implemented in other industries in order to promote a new technology. In the case of this study, promotion of low or non-CO₂-emitting facilities is of interest. Rebates for renewable energy systems are often between \$300k and \$1M per project but this represents less than 5% of the capital required for many plants. This amount is not significant in our analysis given that distributed stations with no form of sequestering carbon requires approximately \$2M in capital while remote stations require over \$100M. In order for capital cost credits to be effective by themselves, we tested a credit of 50% of the production, terminal, and delivery depreciable capital on low or non-CO₂-emitting facilities. This high level of capital cost credit succeeded in shifting the hydrogen build-out: the resulting infrastructure is in Figure 94. If the credit is in effect for 5 years in Los Angeles, this would result in a government expenditure of approximately \$2.76B, out of the total \$15.59B infrastructure cost. Thus policies that provide capital cost credits could facilitate the build-out of remote production: however, they are costly. More interesting is that the pump price of hydrogen over those years would decrease as shown in Figure 95. In the baseline case, hydrogen would cost \$2.36 - \$2.40/kg H₂ during the 2027 - 2031 years. With this policy implemented the cost would be between \$2.24 - \$2.30/kg H₂. Also nuclear options achieve pump prices of less than \$3.00/kg H₂.

Figure 94. Infrastructure for 50% Depreciable Capital Credit to low carbon pathways

Figure 95. Pump Price with 50% Capital Cost Credit

5.7 Additional Cities

Thus far all studies and sensitivities have been conducted for Los Angeles. H2A's Delivery Scenario Analysis Model (HDSAM) city database includes over 400 cities with information about their area, population and ratio of vehicles to people. When all the cities are graphed in terms of vehicles and area we can make several conclusions about Los Angeles and how representative its analysis would be for other U.S. cities.

The database of cities indicate that the majority of U.S. cities are small in area and small in demand (inferred from number of vehicles) as is evident by the clustering of points in the bottom quadrant of Figure 96. Indianapolis is representative of these cities. On the other end of the trend line are large cities with large demand, such as New York City. New York City, however, is in a class by itself in that it is significantly larger than all other cities. Several cities have atypical areas and/or populations and do not fall along the trend line. Above the curve are cities that have large area but small demand for its size. Several cities are in this category but Atlanta is probably the best example. Below the curve are cities with small area, large demand. Los Angeles is representative of this set of conditions. Thus Los Angeles is not a typical U.S. city and the analysis done for this city, while important, is not representative of the majority of cities. However, because of its large vehicle volume and location in an environmentally friendly state, DOE has selected it as a lighthouse city for hydrogen roll out. To understand how the hydrogen build out would progress in other parts of the nation, further analysis is needed to review Indianapolis, Atlanta, and New York City with similar sensitivities as those presented for Los Angeles.

Figure 96. City Database from HDSAM

6 Conclusions & Recommendations

There are two primary reasons to study the technology and economics of hydrogen infrastructures. The first is to reduce emissions (both regulated and greenhouse gas) associated with passenger vehicles. Our estimates indicate that gasoline vehicles in Los Angeles emitted approximately 120,000 TPD of CO₂ emissions in 2005. Thus providing an efficient, cost-effective, clean alternative, i.e. direct hydrogen fuel cell vehicles, would substantially reduce passenger vehicle tailpipe emissions. With the source of emissions transferred from the individual cars to production plants one is better able to collect and discard those emissions. The second major reason for exploring hydrogen production is to reduce US dependency on foreign oil. A significant fraction of US transportation oil is of foreign origin. Thus, our domestic economy, which is dependent on transportation, is greatly impacted by the supply and price of foreign oil. A transition to a domestically sourced fuel supply, whether renewable or carbon based, would significantly reduce foreign dependence. The recommendations provided in this document are based on achieving these two goals.

6.1 Conclusions

Based on economics alone with no outside influences, an infrastructure of 1.5 TPD Forecourt SMR will naturally arise as the most cost effective hydrogen pathway. However, the dominance of 1.5 TPD SMR is largely dependent on installed capital cost. Should the depreciable capital of these production facilities be 78% higher⁷², then the Forecourt SMR will be important in the short run but the cost of larger central plants will be competitive at higher demands. Any existing hydrogen that is available at marginal cost in the early transition years will not be beneficial because the capital required to manipulate small amounts of hydrogen for transport to distribution facilities are significant. Increasing demand rates and rental property costs within city limits are not effective levers with which to modify the naturally resulting infrastructure. Expediting pipeline availability and using more aggressive pipeline costs similarly had no effect. A doubling of natural gas prices did result in a switch over to Coal Gasification technologies at demand levels of 3180 TPD and natural gas prices of \$14.22/GJ. Plants that used municipal solid waste (MSW) as both a feedstock and a revenue source⁷³ are competitive with the 1.5TPD Forecourt SMR. They were more cost effective than the Forecourt SMRs at demands greater than 1420 TPD and MSW revenues greater than \$7.3/ton.

Government mandates are the externalities which most greatly impact how the hydrogen infrastructure will develop. Mandates for carbon sequestration or renewable feedstock tend to drive the infrastructure to central plants solutions. The earlier the mandate is implemented the higher the capital costs of the infrastructure, the lower the emissions over the transition period, and the higher the \$/kg hydrogen to the consumer.

Government imposition of a carbon tax is also effective in altering the production infrastructure build-out but only when the tax is above \$132/ton CO₂.

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⁷² Expert opinions on costs of this solution varied from an optimistic lower bound cost which was used in the baseline analysis to a pessimistic upper bound cost estimate which was as much as 78% higher than the baseline. Because of the large variation in opinion the production option was carried through the analysis as two distinct options, a lower bound and upper bound.

⁷³ In the waste disposal industry it is common for waste haulers to pay disposal facility a tipping fee for unloading. This fee was counted a revenue source (similar to a byproduct) in the MSW gasification production facilities.

6.2 Recommendations for Production Technologies

Clarify capital costs for 1.5TPD SMR systems.

Modeling suggests 1.5 TPD forecourt SMR will be the dominant low cost hydrogen production method (achieving \$2.40/kg in 2020) provided the lower bound capital cost estimates are achieved. Distributed hydrogen generation fosters the transition to hydrogen fueling and thus should be encouraged even though it itself is not a renewable technology. It is recommended that further research be dedicated to both narrowing cost estimate disparities and achieving the lower bound capital cost target for 1.5 TPD SMR systems.

Explore the role of 0.1 TPD systems during the very early years of the transition.

Analysis indicates that 0.1 TPD systems are only more cost effective than the larger 1.5 TPD systems if hydrogen demand remains below 0.3 TPD over several years. While 0.1 TPD systems could play a pivotal role in the very early years of the transition, such a low demand scenario was not the focus of HyPro modeling. Additional analysis should be conducted with a focus on 2009-2015.

Develop lower cost sequestration systems.

The naturally resulting 1.5 TPD SMR infrastructure does not help with the two objectives of transitioning to hydrogen. Those systems require natural gas and thus one is trading dependency on foreign oil with dependency on foreign natural gas. In addition, there is no cost-effective sequestration system at small forecourt scale so emissions are still higher than necessary. Spending resources on lowering sequestration costs at any scale would facilitate achievement of the primary objective of hydrogen transition.

Improve efficiency and/or cost of production from renewable feedstocks.

1.5 TPD SMR infrastructure naturally results because it is the lowest cost solution over the predicted scenarios of demand levels and rates. Research efforts to decrease the capital cost or increase the efficiency of renewable hydrogen systems at many capacity levels would potentially allow it to be selected and reduce the overall carbon emissions from the infrastructure.

Further explore Municipal Solid Waste hydrogen production systems.

Hydrogen production using Municipal Solid Waste (MSW) (i.e. trash) as a feedstock was identified as very cost competitive provided the MSW is available at a low cost. Further investigation of these systems and actual feedstock costs should be conducted.

6.3 Recommendations for Infrastructure Systems

Reduce costs of liquefaction.

Production-associated costs represent approximately 52% of total infrastructure costs, with the remaining 48% associated with terminals, delivery and dispensing operations. Delivery costs are inversely proportional to delivery volume. Analysis indicates that liquid truck transport of hydrogen is the best alternative until demand grows large enough to support a pipeline network. However, the cost benefits of liquid transports are offset by the high capital cost and electricity requirements of hydrogen liquefaction. Consequently, focused research to improve the efficiency and reduce the capital cost of liquefaction facilities could have a substantial impact on hydrogen cost. Shifting the lowest cost pathway from that of a distributed network to that of centralized production with liquid delivery would simplify the very early years of hydrogen transition and facilitate the eventual adoption of pipelines.

Reduce high pressure storage costs.

Hydrogen storage is required at both the terminal and dispensing facilities to ensure reliable supply. Moderate/High pressure gaseous storage is a substantial cost element.

Consequently, research to reduce the capital cost of stationary gaseous bulk storage is recommended.

Develop less labor intensive piping installation methods.

A large portion of pipeline installed capital costs are associated with the installation labor requirements. Since labor costs are approximately constant whether a large or small diameter pipeline is installed, pipelines are generally only cost effective at large sizes. Reducing the costs of the labor associated with pipeline installation would lower overall hydrogen delivery cost and help remote central plants be more competitive with forecourt systems.

6.4 Policy Recommendations

As our baseline research indicated the resulting hydrogen infrastructure build out would be 1.5 TPD forecourt SMRs. This build out does not address our primary goals of; a) reducing emissions, and b) reducing US dependency on foreign energy sources. Thus additional government assistance is necessary to further advance those goals. Our analysis indicates that further consideration of the following policies may be beneficial to meeting the emissions and independence targets.

Implement mandates to meet emission and independence objectives.

Imposing mandates is the most cost effective way for the government to drive infrastructure towards lower carbon emissions and independence from foreign resources. The implementation schedule can be immediate or gradual as needed to meet the hydrogen program objectives. Additionally, mandates should require minimal government expenditures to deploy and enforce.

Implement government subsidies to meet emission and independence objectives.

Our analysis studied capital cost incentives of 50% and found them to be effective in shifting the infrastructure to a cleaner domestic energy source (i.e. Coal with Sequestration and Pipelines). However the necessary incentive appears to be a substantial fraction of initial capital cost. While 50% capital cost incentives are effective our recommendation is that additional studies be conducted to find the tipping point of the analysis.

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8 Abbreviations

CCSD Carbon Capture, Storage and Disposal
DCF Discounted Cash Flow
DR Discount Rate
DTI Directed Technologies, Inc.
GWP Global Warming Potential
LDV Light Duty Vehicles
MSW Municipal Solid Waste
NREL National Renewable Energy Laboratory
TPD metric ton per day (1000kg/day)

9 *Appendices*

9.1 Appendix A – Excel Database

9.1.1 Worksheet Layout Design

Figure 97 shows a portion of a technology worksheet (global worksheets are structured similarly). Column A notifies MatLab what type of variable it is receiving. MatLab script file, H2XLSRead.m (the m-file for reading in HyPro worksheets) scans sequentially down the leftmost column looking for “Axis” or “Var...”, where “...” is a variable type. Valid variable types are shown in Figure 98.

Axis tags	Axis names	Variable names	Not loaded into MATLAB	Axis definitions	Variable data
Axis	CY	Year		(2005:2070)	
Axis	PY	Year		(1:20)	
VarData	DesignCapacity	[kgH ₂ /day]		100	
VarData	DesignCapacity	[kgH ₂ /year]		36,500	
VarLinear	MaxUtilization	[% of DesignCapacity/yr.]		(PY)	
Data				1	70.00%
End				20	70.00%
VarData	MACRSRecoveryPeriod	[Years]		7	
VarData	TaxRate (Federal)	[%]		35%	
VarData	TaxRate (State)	[%]		6%	
VarLinear	TaxRate			(PY,CY)	
Data				2005	2070
End				1	38.90%
VarLinear	H ₂ Subsidy	[\$]		20	38.90%
Data				(CY)	
End				2005	2070
VarCubic	FeedstockEnergyRatios			(Feedstock,CY)	
Data				2005	2015
				2030	2070
	[GJH ₂ /GJFeedstock]	Commercial Natural Gas		0	0
	[GJH ₂ /GJFeedstock]	Industrial Natural Gas		0	0
	[GJH ₂ /GJFeedstock]	Electric Utility Natural Gas		0	0
	[GJH ₂ /GJ]	Commercial Electricity		0	0
	[GJH ₂ /GJ]	Industrial Electricity		0.621393493	0.685806233
	[GJH ₂ /GJFeedstock]	Electric Utility Steam Coal		0	0
	[GJH ₂ /GJFeedstock]	Diesel Fuel		0	0
	[GJH ₂ /GJFeedstock]	Biomass		0	0
	[GJH ₂ /GJFeedstock]	Ethanol		0	0
	[GJH ₂ /GJFeedstock]	Methanol		0	0
	[GJH ₂ /GJFeedstock]	Gasoline		0	0
	[GJH ₂ /GJ]	Steam		0	0
	[GJH ₂ /L]	Cooling Water		0.000109275	0.000109275
	[GJH ₂ /L]	Deminerlized Water		0.009564567	0.009564567
	[GJH ₂ /L]	Process Water		0	0
	[GJH ₂ /Barrel]	Bio-oil		0	0
				2005	2015
				2030	2070
	Capital (Depreciable, Direct)	(Component,CY)			
	Uninstalled Costs			\$307,911.91	\$167,041.20
	Installation Costs			10%	\$116,947.37
	Installed Costs			\$338,703.11	\$183,745.32
					\$128,642.11

Figure 97. Annotated Worksheet Snippet

Type	Interpolation	Extrapolation	Deletion
(none)	None	none	no
Linear	Linear	none	Yes
Cubic	Cubic	cubic	Yes

Figure 98. Valid Variable Types

These and other items appearing in the leftmost column are called **tags**. In the case of Axes, the definition is read from the third column to the right of the name (typically Column E). In the case of Variables, the m-file looks for a tag called “Data” to follow the “Var...” statement, and begins reading in the same column (Column E), but in the row containing the “Data” tag. If the first cell of data read contains a non-numeric value, the data is assumed to be non-numeric and the program reads in that cell and then looks for the next Axis or Variable. If that cell contains a numeric value, however, the m-file continues reading data left-to-right until a non-numeric or empty cell is encountered. This sets the width of the variable. The program then looks for an “End” tag in the first column. If no “End” tag is

found, the variable is considered to be a row vector or scalar. If an “End” tag is found, the m-file takes the aforementioned width and reads all values in that column range (even non-numeric ones) down to (and including) the row containing the “End” tag.

For convenience, you can combine the “Data” tag with the “Var” tag to get “VarData” if no mapping is needed. This saves space on the spreadsheet.

The current worksheets use a loose pattern/color-coding scheme for the convenience of the user, but this is not required and H2XLSRead.m completely ignores it.

9.1.2 Technology Worksheets

For HyPro to work correctly, the following Axes and Variables need to be present in **all** technology worksheets:

IClass	Unique four digit classification of a technology which assists in the matching of pathways STANDARD VALUE: [1,3,1,3]
OClass	A three digit classification of a technology that needs to be equal to the first three digits of the IClass of the portion of the infrastructure immediately downstream in order to marry the components into a pathway STANDARD VALUE: [4,8,1]
CYStart	This technology cannot be built before calendar year <i>CYStart</i>
CYStop	This technology cannot be built after calendar year <i>CYStop</i>
CY	Calendar year (2005, 2006, ...; typically CYStart to CYStop). Written in square brackets with a colon STANDARD VALUE: [2005:2050]
IRR	Discount Rate (DR) for discounted cash flow (DCF) analysis when considering building STANDARD VALUE: 10% ⁷⁴
DepreciationLength	Modified Accelerated Cost Recovery System (MACRS) schedule of what percentage of a capital assets cost can be depreciated in each year after purchase. STANDARD VALUE: 20 years for Centrals/City-Gates, 7 years for Forecourts ⁷⁴
AnalysisPeriod	DCF analysis period for IRR, IRRStranded STANDARD VALUE: <i>Life</i> /2 ⁷⁴
Life	Lifetime in years after built plants are decommissioned STANDARD VALUE: 10 years for Centrals/City-Gates, 20 years for Forecourts
PY	Plant Years (1, 2, ...; typically 1 to Lifetime). Written in square brackets with a colon STANDARD VALUE: [1:40]

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⁷⁴ Rutkowski, M.D., Kuehn, N.J. H2A Central Cash Flow Modeling Tool v1.0.9 (Central Coal, SMR). US DOE/NETL. 27 June 2005. & James, B.D. H2A Central Cash Flow Modeling Tool v1.0.9 (Forecourt SMR). 20 January 2005. & James, B.D. H2A Central Cash Flow Modeling Tool v1.0.9 (Forecourt Electrolysis). 11 July 2005. & Allen, D., Mears, D. H2A Central Cash Flow Modeling Tool v1.0.9 (Central Nuclear). 17 June 2005. & Mann, MK. H2A Central Cash Flow Modeling Tool v1.0.9 (Biomass). 4 January 2005.

DesignCapacity	Maximum possible kg of H2 this technology can generate in a year STANDARD VALUE: 138,476,255 ⁷⁵
CapacityFactor	Limit on total yearly utilization to allow for month-to-month demand variations STANDARD VALUE: 90% for Centrals/City-Gates, 70% for Forecourts ⁷⁴
Location	Index defined on city page which connects technology to a regional, central, city gate or forecourt location STANDARD VALUE: 1, 2, 3, 4 or 5
DepreciableCapital	All component costs which depreciate over time (such as compressors), in total \$. STANDARD VALUE: \$142,295,768.72 ⁷⁵
LandRequired	Does not account for rented land (which is included in OMFixedCosts) STANDARD VALUE: City-Gate Coals use 25 acres ⁷⁶ Central SMR uses 20 acres ⁷⁷ All other plants vary by process ⁷⁵
FixedOM	Costs associated with plant operation, expressed in [\$ /yr] and calculated as percent of Depreciable Capital STANDARD VALUE: Overhead & G&A – 20%, Prop Tax & Ins – 2%, Maint. 0.6%
OtherFixed	Other Costs associated with plant operation, expressed in [\$ /yr]
FeedstockEfficiency	Ratio of the net hydrogen heating value out of the production facility to the gross feedstock lower heating value consumed in the production facility. (LHVH2/LHVfeedstock). SMR based off of consensus of data from H2A, ACPI, H2Gen and Haldor Topsoe ⁷⁵ STANDARD VALUE: 0.75
OtherVariableOM	Costs which vary by the production quantity such as waste treatment, expressed in [\$ /kg H2] STANDARD VALUE: \$0.0404 ⁷⁴
ByproductEfficiency	Ratio of the net hydrogen heating value out of the production facility to the byproduct's lower heating value also produced in the production facility.
Emissions	Amount in [kg/kg H2] of emissions associated with a given technology STANDARD VALUE: 0 – 26kg/kg H2 ⁷⁸
ReplacementCosts	Costs associated with regularly scheduled replacements in total \$

⁷⁵These costs are taken from the H2A Components model.

⁷⁵ Rutkowski, M.D., Kuehn, N.J. H2A Central Cash Flow Modeling Tool v1.0.9 (Central Coal, SMR). US DOE/NETL. 27 June 2005. & James, B.D. H2A Central Cash Flow Modeling Tool v1.0.9 (Forecourt SMR). 20 January 2005. & James, B.D. H2A Central Cash Flow Modeling Tool v1.0.9 (Forecourt Electrolysis). 11 July 2005. & Allen, D., Mears, D. H2A Central Cash Flow Modeling Tool v1.0.9 (Central Nuclear). 17 June 2005. & Mann, MK. H2A Central Cash Flow Modeling Tool v1.0.9 (Biomass). 4 January 2005. & Rutkowski, M.D., Kuehn, N.J., & Schoff, R.L. Hydrogen Production and Delivery Pathways. US DOE/NETL. September 2005.

⁷⁶ Rutkowski, M. Parsons. Telephone communication. 28 March 2006

⁷⁷ James, B.D. et al. Directed Technologies, Inc. Assumption. & "Hydrogen Infrastructure Report" prepared by Directed Technologies Inc. for The Ford Motor Company under contract to the US DOE. July 1997.

⁷⁸ Reference Appendix F – Computing Emissions of Production Plants for complete information about how emissions are computed.

	STANDARD VALUE: City-Gates use nominal values (0.5%/year) ⁷⁴
LearningFactor (P & D-LT)	An estimation of cost improvement expected in each doubling of units produced due to learning effects. Factors are presented in a matrix that allows fabrication of one kind of production asset to be counted towards the cost reduction of another kind of asset. STANDARD VALUE: 0.97
LearningFactorStart (P & D-LT)	The learning factor multiplier used to modify the capital cost reported in the DepreciableCapital. STANDARD VALUE: 1 Typically, this value is 1 unless the capital cost reported does not correlate with the InitialUnitNo desired.
ExternalBuildFixed	Number of systems built in each specified year that occurs regardless of whether the asset is selected by HyPro to be built. This is used to simulate hydrogen facility builds for non-hydrogen vehicle applications or for facility builds in other cities.
InitialUnitNo (P & D-LT)	Initial number of units available when learning factor begins to take effect STANDARD VALUE: 500
FixedOMOverall(D-PL)	Fixed annual operation and maintenance cost expressed in \$
FixedOMPerMile(D-PL)	Fixed annual operation and maintenance cost expressed in \$/mile
DepreciableCapitalPerMile (D-PL)	

Values used to populate these technology worksheets are taken from a variety of sources. Column I or L on these sheets provides a reference number. There is a supporting worksheet called Reference List which identifies by number all references used in the database. Reference sources have been identified for all technology worksheet values.

9.1.3 Global Worksheet

For HyPro to work correctly, the following Axes and Variables need to be present in the Global Worksheet:

CYStart	The calendar year of the first index of Global Variables indexed by year
CYStop	The calendar year of the last index of Global Variables indexed by year
CY	Calendar year (2005, 2006, ...; typically CYStart to CYStop). Written in square brackets with a colon STANDARD VALUE: [2005:2050]
CYBegin	The first calendar year to be simulated
CYEnd	The last calendar year to be simulated
FeedstockCosts	Feedstock costs converted from H2A into \$/GJ of feedstock ⁷⁴
ByproductCredits	Amount of revenues that can be claimed from selling a byproduct of the hydrogen production such as electricity,

	expressed in \$/GJ STANDARD VALUE: \$8.33 /GJ (Electricity)
DepreciationSchedule	Modified Accelerated Cost Recovery System (MACRS) schedule of what percentage of a capital assets cost can be depreciated in each year after purchase. ⁷⁹
EmissionsTax	Emission tax entered in \$/kgH ₂ of regulated emission STANDARD VALUE: \$0.025 ⁸⁰

9.1.4 City/Region Worksheet

For HyPro to work correctly, the following Axes and Variables need to be present in City/Region Worksheet:

TaxRate	Plant owner is assumed to be a large company, so taxes <0 can occur ⁸¹ STANDARD VALUE: 38.9% ⁷⁴
Demand	Inelastic projection of Hydrogen usage over the analysis period. Current Demand projection options from US DOE Transition Scenario Analysis, written in kg of H ₂ /year
Region Size	Area in miles of the city or region needed for station spacing STANDARD VALUE: 1668 mi ²
LandCosts	Regional real estate values at different remote sites. STANDARD VALUE: \$400,000/acre
Distance	Defined distances for remote production. Distributed production is set to zero. STANDARD VALUE: 60 mi (Central)
MinStationSpacing	Spacing between dispensing stations such that the region has a minimum coverage. Only influences the initial number of stations built during the initial year of the simulations.

9.1.5 Increasing Technology Options

During sensitivity analysis it may be necessary for additional technology options to be created. In order to do so, a new worksheet must be inserted into the database. This can be done using the Excel command for a new worksheet or by creating a copy of an existing worksheet. Creating a copy of a similar technology is recommended as the formatting needed for the analysis is already complete. The new technology should be located in its appropriate grouping; production, terminal, delivery or dispensing. The numerical values should be adjusted appropriately based on the definitions provided in Figure 18, Figure 24, Figure 26, and Figure 32. The I Class and O Class cells (E2 and E3) should be changed such that the I Class variable is a unique set of numbers and the O Class variable is assigned according to the downstream component to be included in the pathway. The I Class of each option is listed as the option # in the figures listed above. This approach can also be taken to evaluate different variations of the same technology simultaneously such as an optimistic and pessimistic case.

⁷⁹ Financial Assumptions Used in the H2A Analysis. http://www.hydrogen.energy.gov/h2a_prod_rules.html.

⁸⁰ James, B.D. et al. Directed Technologies, Inc. Assumption

⁸¹ A tax credit is accrued when depreciable expenses exceed revenues.

9.1.6 Increasing Feedstock Options and other Arrays

When creating new technologies they may require a different type of feedstock. The feedstock list can be expanded by inserting a row between the 'Data' and the 'End' tags on the Global tab. That row will need to be inserted in every technology tab as well so that when MatLab does array multiplication the arrays are of the same size and no errors occur. The horizontal arrays can also be expanded, by inserting columns. An example is the linear variable Depreciable Capital. If additional columns are added to that variable the curve fit can be more exact.

9.2 Appendix B – HyPro Production Technology Descriptions

This appendix contains a short description of each of the 34 production technologies included in the input database. Additionally, all Excel input worksheets for the model are contained in Appendix J – HyPro Input Database. That appendix is inclusive of technology, city, global and supplemental worksheets as described in Figure 11 of the main document.

C,COAL-G,2005

Central Coal Gasification Plant with 2005 Technology

To arrive at a cost estimate for hydrogen, the design included commercially available process technology obtained from verifiable sources. The plant utilized commercially available technology including a Wabash River-scale Conoco-Phillips (EGas) gasifier, conventional gas cooling, commercial shift conversion and acid gas cleanup, commercial sulfuric acid technology, and commercial pressure swing adsorption (PSA). The EGas gasifier is the gasifier of choice for this study since it has been operated on both bituminous and sub-bituminous coals.

C,COAL-G,2015

Central Coal Gasification Plant with 2015 Technology

Hot raw gas from the E-Gas gasifier is cooled and sent to the SCOHS process for desulfurization. Elemental sulfur is produced as a byproduct. The clean gas is filtered then goes through a hydrogen separation membrane where the surface shift reaction occurs and hydrogen is separated from CO₂. A portion of the hydrogen is fired to heat compressed air entering the ITM oxygen separation unit. Pure oxygen produced from the ITM is cooled and compressed for use in the gasifier. The remaining hydrogen is compressed for product delivery. The CO₂-rich stream is fired with oxygen and expanded to recover energy as power.

C,COAL-G,2025

Central Coal Gasification Plant with 2025 Technology

Hot raw gas from the transport gasifier is sent to the hot gas desulfurization process for desulfurization. Elemental sulfur is produced as a byproduct. The clean filtered hot gas then goes through a hydrogen separation membrane where the shift reaction occurs and hydrogen is separated from CO₂. A portion of the hydrogen is fired to heat compressed air entering the ITM oxygen separation unit. Heat for the air is also extracted from the hot CO₂ stream with a high temperature heat exchanger. Additional hydrogen is used to produce power from a combined cycle SOFC. Pure oxygen produced from the ITM is cooled and compressed for use in the gasifier. The remaining hydrogen is compressed for product delivery. The CO₂-rich stream is fired with oxygen and expanded to recover energy as power.

C,COAL CCS,2005

Central Coal Gasification Plant with 2005 Technology and Carbon Sequestration

To arrive at a cost estimate for hydrogen, the design included commercially available process technology obtained from verifiable sources. The plant utilized commercially available technology including a Wabash River-scale Destec (EGas) gasifier, conventional gas cooling, commercial shift conversion and acid gas cleanup, commercial sulfuric acid technology, and commercial pressure swing adsorption (PSA). Two-stage Selexol is used to remove CO₂. CO₂ is compressed to 2200 psi for sequestration. The EGas gasifier is the gasifier of choice for this study since it has been operated on both bituminous and sub-bituminous coals.

C,COAL CCS,2015

Central Coal Gasification Plant with 2015 Technology and Carbon Sequestration

Hot raw gas from the E-Gas gasifier is cooled and sent to the SCOHS process for desulfurization. Elemental sulfur is produced as a byproduct. The clean gas is filtered goes through a hydrogen separation membrane where the surface shift reaction occurs and hydrogen is separated from CO₂. A portion of the hydrogen is fired to heat compressed air entering the ITM oxygen separation unit. Pure oxygen produced from the ITM is cooled and compressed for use in the gasifier. The remaining hydrogen is compressed for product delivery. The CO₂-rich stream is fired with oxygen and expanded to recover energy as power. The CO₂ exhaust is compressed for pipeline delivery.

C,COAL CCS,2025

Central Coal Gasification Plant with 2025 Technology and Carbon Sequestration

Hot raw gas from the transport gasifier is sent to the hot gas desulfurization process for desulfurization. Elemental sulfur is produced as a byproduct. The clean filtered hot gas then goes through a hydrogen separation membrane where the shift reaction occurs and hydrogen is separated from CO₂. A portion of the hydrogen is fired to heat compressed air entering the ITM oxygen separation unit. Heat for the air is also extracted from the hot CO₂ stream with a high temperature heat exchanger. Additional hydrogen is used to produce power from a combined cycle SOFC. Pure oxygen produced from the ITM is cooled and compressed for use in the gasifier. The remaining hydrogen is compressed for product delivery. The CO₂-rich stream is fired with oxygen and expanded to recover energy as power. The CO₂ exhaust is compressed for pipeline delivery.

R,COAL-G,2005

Regional Coal Gasification Plant with 2005 Technology

To arrive at a cost estimate for hydrogen, the design included commercially available process technology obtained from verifiable sources. The plant utilized commercially available technology including a Wabash River-scale Conoco-Phillips (EGas) gasifier, conventional gas cooling, commercial shift conversion and acid gas cleanup, commercial sulfuric acid technology, and commercial pressure swing adsorption (PSA). The EGas gasifier is the gasifier of choice for this study since it has been operated on both bituminous and sub-bituminous coals.

R,COAL-G,2015

Regional Coal Gasification Plant with 2015 Technology

Hot raw gas from the E-Gas gasifier is cooled and sent to the SCOHS process for desulfurization. Elemental sulfur is produced as a byproduct. The clean gas is filtered then goes through a hydrogen separation membrane where the surface shift reaction occurs and hydrogen is separated from CO₂. A portion of the hydrogen is fired to heat compressed air entering the ITM oxygen separation unit. Pure oxygen produced from the ITM is cooled and compressed for use in the gasifier. The remaining hydrogen is compressed for product delivery. The CO₂-rich stream is fired with oxygen and expanded to recover energy as power.

R,COAL-G,2025

Regional Coal Gasification Plant with 2025 Technology

Hot raw gas from the transport gasifier is sent to the hot gas desulfurization process for desulfurization. Elemental sulfur is produced as a byproduct. The clean filtered hot gas then goes through a hydrogen separation membrane where the shift reaction occurs and hydrogen is separated from CO₂. A portion of the hydrogen is fired to heat compressed air entering the ITM oxygen separation unit. Heat for the air is also extracted from the hot CO₂

stream with a high temperature heat exchanger. Additional hydrogen is used to produce power from a combined cycle SOFC. Pure oxygen produced from the ITM is cooled and compressed for use in the gasifier. The remaining hydrogen is compressed for product delivery. The CO₂-rich stream is fired with oxygen and expanded to recover energy as power.

R,COAL CCS,2005

Regional Coal Gasification Plant with 2005 Technology and Carbon Sequestration

To arrive at a cost estimate for hydrogen, the design included commercially available process technology obtained from verifiable sources. The plant utilized commercially available technology including a Wabash River-scale Destec (EGas) gasifier, conventional gas cooling, commercial shift conversion and acid gas cleanup, commercial sulfuric acid technology, and commercial pressure swing adsorption (PSA). Two-stage Selexol is used to remove CO₂. CO₂ is compressed to 2200 psi for sequestration. The EGas gasifier is the gasifier of choice for this study since it has been operated on both bituminous and sub-bituminous coals.

R,COAL CCS,2015

Regional Coal Gasification Plant with 2015 Technology and Carbon Sequestration

Hot raw gas from the E-Gas gasifier is cooled and sent to the SCOHS process for desulfurization. Elemental sulfur is produced as a byproduct. The clean gas is filtered then goes through a hydrogen separation membrane where the surface shift reaction occurs and hydrogen is separated from CO₂. A portion of the hydrogen is fired to heat compressed air entering the ITM oxygen separation unit. Pure oxygen produced from the ITM is cooled and compressed for use in the gasifier. The remaining hydrogen is compressed for product delivery. The CO₂-rich stream is fired with oxygen and expanded to recover energy as power. The CO₂ exhaust is compressed for pipeline delivery.

R,COAL CCS,2025

Regional Coal Gasification Plant with 2025 Technology and Carbon Sequestration

Hot raw gas from the transport gasifier is sent to the hot gas desulfurization process for desulfurization. Elemental sulfur is produced as a byproduct. The clean filtered hot gas then goes through a hydrogen separation membrane where the shift reaction occurs and hydrogen is separated from CO₂. A portion of the hydrogen is fired to heat compressed air entering the ITM oxygen separation unit. Heat for the air is also extracted from the hot CO₂ stream with a high temperature heat exchanger. Additional hydrogen is used to produce power from a combined cycle SOFC. Pure oxygen produced from the ITM is cooled and compressed for use in the gasifier. The remaining hydrogen is compressed for product delivery. The CO₂-rich stream is fired with oxygen and expanded to recover energy as power. The CO₂ exhaust is compressed for pipeline delivery.

RMM,COAL CCS, 2015

Regional Coal Gasification Plant with 2025 Technology, Carbon Sequestration, and Mixed Mode Delivery

Hot raw gas from the E-Gas gasifier is cooled and sent to the SCOHS process for desulfurization. Elemental sulfur is produced as a byproduct. The clean gas is filtered then goes through a hydrogen separation membrane where the surface shift reaction occurs and hydrogen is separated from CO₂. A portion of the hydrogen is fired to heat compressed air entering the ITM oxygen separation unit. Pure oxygen produced from the ITM is cooled and compressed for use in the gasifier. The remaining hydrogen is compressed for product delivery. The CO₂-rich stream is fired with oxygen and expanded to recover energy as power. The CO₂ exhaust is compressed for pipeline delivery.

CG,COAL-G,2005

City Gate Coal Gasification Plant with 2005 Technology

A City Gate hydrogen plant fed with Pittsburgh No. 8 bituminous coal based on the ConocoPhillips E-Gas process. This coal is characterized having high volatility, low ash and moisture content, and high as-received heating value. The pressurized entrained flow E-GAS™ two-stage gasifier uses a coal/water slurry and oxygen to produce a medium heating value fuel gas. The syngas produced in the gasifier first stage at about 1343°C (2450°F) is quenched to 1038°C (1900°F) by reacting with slurry injected into the second stage. Gas leaving the gasifier is cooled in a fire-tube syngas cooler producing high pressure steam. The cooled gas is cleaned of particulate via a cyclone collector followed by a ceramic candle filter. After leaving the particulate control unit, steam is injected into the gas stream and the CO in the syngas is shifted to hydrogen and CO₂ in the shift converter utilizing a sulfur-tolerant shift catalyst. The gas stream is sent to the sulfur removal unit which removes H₂S and some of the CO₂. The clean gas stream then passes through the PSA for final purification of the hydrogen. Regeneration gas from the PSA contains fuel value, and is fed to the HRSG for duct-firing. Regeneration gas from the AGR plant is fed to a sulfuric acid plant.

CG,COAL-G,2015

City Gate Coal Gasification Plant with 2015 Technology

The 2015 plant is based on an E-Gas gasifier but utilizes an ITM membrane for oxygen production, a Selective Oxidation of H₂S (SCOHS) process, and a hydrogen separation membrane. CO₂ recovery is inherent.

CG,COAL-G,2030

City Gate Coal Gasification Plant with 2025 Technology

The 2030 plant is based on an advanced gasifier and more technology developments.

CG,NG-SMR

City Gate Natural Gas Steam Methane Reforming

This system involves a catalytic conversion of the hydrocarbon and steam to hydrogen and carbon oxides. The process consists of three main steps: (1) natural gas reformer/boiler, (2) water gas shift reaction and (3) gas purification. Natural gas is fed to the plant from the pipeline at a pressure of 3.10 MPa. To protect the catalysts in the hydrogen plant, the natural gas has to be desulfurized with a zinc oxide polishing bed before being fed to the reformer. After the reformer, the process gas mixture of CO₂, CO and H₂ passes through a heat recovery step and is fed into a water gas shift reactor to produce additional H₂. Treated gas from the shift reactor is fed directly to the Pressure Swing Adsorption (PSA) process is used for hydrogen purification where hydrogen is purified up to approximately 99.6%. Carbon oxides are limited to 10 ppm in the final hydrogen product.

C,NG-SMR

Central Natural Gas Steam Methane Reforming

Natural gas is fed to the plant from the pipeline at a pressure of 450 psia. The gas is generally sulfur-free, but odorizers with mercaptans 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 of a system of high alloy steel tubes. The reforming reaction is strongly endothermic, and the metallurgy of the tubes usually limits the reaction temperature to 1400-1700°F. The flue gas path of the fired reformer is integrated with additional boiler surfaces to produce about 700,000 lb/hour steam. Of this, about 450,000 lb/hour is superheated to 450 psia and 750°F, to be added to the incoming natural gas. Additional steam from the boiler is sent off-site. After the reformer, the process gas mixture of CO and H₂ passes through a heat

recovery step and is fed into a water gas shift reactor to produce additional H₂. The Pressure Swing Adsorption (PSA) process is used for hydrogen purification, based on the ability to produce high purity hydrogen, low amounts of CO and CO₂ and ease of operation. Shifted gas is fed directly to the PSA unit where hydrogen is purified up to approximately 99.6% based on the ability to produce high purity hydrogen, low amounts of CO and CO₂ and ease of operation. Shifted gas is fed directly to the PSA unit where hydrogen is purified up to approximately 99.6%.

NG-SMR, CCS

Central Natural Gas Steam Methane Reforming with Carbon Sequestration

Natural gas is fed to the plant from the pipeline at a pressure of 450 psia. The desulfurized natural gas feedstock is mixed with process steam to be reacted over a nickel based catalyst contained inside of a system of high alloy steel tubes. The reforming reaction is strongly endothermic, and the metallurgy of the tubes usually limits the reaction temperature to 1400-1700°F. The flue gas path of the fired reformer is integrated with additional boiler surfaces to produce about 700,000 lb/hour steam. Of this, about 450,000 lb/hour is superheated to 450 psia and 750°F, to be added to the incoming natural gas. Additional steam from the boiler is used to regenerate the CO₂. After the reformer, the process gas mixture of CO and H₂ passes through a heat recovery step and is fed into a water gas shift reactor to produce additional H₂. The Pressure Swing Adsorption (PSA) process is used for hydrogen purification, based on the ability to produce high purity hydrogen, low amounts of CO and CO₂ and ease of operation. Shifted gas is fed directly to the PSA unit where hydrogen is purified up to approximately 99.6%. This plant utilizes a proprietary amine-based process to remove and recover 99 percent of the CO₂ from the syngas stream. From the shift reactor, gas is passed through an amine tower where it is contacted counter-currently with a circulating stream of lean aqueous amine solution. The rich amine from the absorber is then sent to a stripper column where the amine is regenerated with a steam boiler to remove the CO₂ by fractionation. The regenerated CO₂ stream is recovered at 27 psia and 121°F and is compressed to be sent off-site. To reach 90 percent CO₂ removal, a secondary MEA treatment process is installed on the reformer stack.

FC,NG-SMR,0.1

Forecourt Natural Gas Steam Methane Reforming, 0.1TPD

The natural gas reforming process is based on 15-atm SMR with hydro-desulfurization pre-treatment and PSA gas cleanup. The PSA is based on 4 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. The product hydrogen exits the PSA at 300psi and is compressed and stored at 6250psi for cascade filling of vehicles.

FC,NG-SMR,1.5 (LCLB)

Forecourt Natural Gas Steam Methane Reforming, 1.5 TPD, Learning Curve Implemented, Lower Bound Capital Costs

The natural gas reforming process is based on 20-atm conventional tube-in-shell Steam Methane Reactor (SMR) with hydro-desulfurization pre-treatment and PSA gas cleanup. The PSA is based on 4 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. Because smaller units are more amenable to factory building than very large units, two 750kgH₂/day reactors are assumed rather than a single 1500kg/day unit. The system is assumed to be air cooled (and thus requires no cooling water flow). The product hydrogen exits the PSA at 300psi and is compressed and stored at 6250psi for cascade filling of vehicles.

FC,NG-SMR,1.5 (LCUB)

Forecourt Natural Gas Steam Methane Reforming, 1.5 TPD, Learning Curve Implemented, Upper Bound Capital Costs

The natural gas reforming process is based on 20-atm conventional tube-in-shell Steam Methane Reactor (SMR) with hydro-desulfurization pre-treatment and PSA gas cleanup. The PSA is based on 4 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. Because smaller units are more amenable to factory building than very large units, two 750kgH₂/day reactors are assumed rather than a single 1500kg/day unit. The system is assumed to be air cooled (and thus requires no cooling water flow). The product hydrogen exits the PSA at 300psi and is compressed and stored at 6250psi for cascade filling of vehicles.

FC,MMEL-E,0.1

Forecourt Electrolysis, 0.1 TPD

The system is modeled on high pressure (300psi) alkaline electrolysis and subsequent compression to 6250kpsi for storage and dispensing to fuel cell vehicles. Oxygen capture (& subsequent sale as a co-product) is not assumed.

FC,MMEL-E,1.5

Forecourt Electrolysis, 1.5 TPD

The system is modeled on a current (2005) year technology, pressurized (300psi) alkaline electrolysis and subsequent compression to 6250kpsi for storage and dispensing to fuel cell vehicles. Oxygen capture (& subsequent sale as a co-product) is not assumed.

FC,ETH,1.5

Forecourt Ethanol Reforming, 1.5 TPD

The reforming process is based on 20 bara ethanol reformer with HT shift and PSA gas cleanup. Process based on 20 bara steam reforming of ethanol. The stream is sent to a high temperature shift reactor for converting CO from reformed ethanol stream and then to a PSA unit for purification. The resulting purified hydrogen stream is compressed to 7000 psi for cascade dispensing to 5000 psi vehicle tanks. The unit is assumed to be factory built (as opposed to on-site construction) and is skid-mounted for easy, rapid installation.

C,N-HPE

Central Nuclear High Pressure Electrolysis, 2015 Technology

The system examined is based on the application of current nuclear energy for hydrogen production, specifically an Advanced Light Water Reactor (ALWR) providing electric power to a high pressure water electrolysis plant.

C,N-HTE

Central Nuclear High Temperature Electrolysis, 2025 Technology

The systems examined are based on the application of an advanced HTGR plant (4 x 600MWt modules) providing high efficiency electric power and high temperature (steam) to a central high temperature electrolysis (HTE) plant. HTE operation and performance is modeled on the design being developed by INL including published pilot-scale plant parameters.

C,N-SITHC

Central Nuclear Sulfur Iodine Thermochemical Process, 2025 Technology

The systems examined are based on the application of an advanced HTGR plant (4 x 600MWt modules) providing direct process heat to a central S-I water splitting process plant.

R,BIO-G

Regional Biomass Gasification

The systems examined are based on the Battelle/FERCO indirectly-heated biomass gasifier, conventional catalytic steam reforming, water gas shift, and pressure swing adsorption 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.

RMM,BIO-G

Regional Biomass Gasification with Mixed Mode Delivery

The systems examined are based on the Battelle/FERCO indirectly-heated biomass gasifier, conventional catalytic steam reforming, water gas shift, and pressure swing adsorption 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.

CG,EX

City Gate Existing Hydrogen Supply

Existing facility in the region of interest with surplus supply willing to provide this surplus at a lower variable cost.

C,MSW (-35)-G

Central Municipal Solid Waste Gasification, \$35/ton feedstock cost

The system is modeled as a 150 TPD MSW-to-hydrogen plant with capital cost of \$126M (total depreciable cost) and 65% efficiency based on information from an unnamed industrial company. The assumed technology was not specified but is assumed to be either a conventional or plasma gasification process.

C,MSW (+35)-G

Central Municipal Solid Waste Gasification, \$35/ton feedstock revenues

The system is modeled as a 150 TPD MSW-to-hydrogen plant with capital cost of \$126M (total depreciable cost) and 65% efficiency based on information from an unnamed industrial company. The assumed technology was not specified but is assumed to be either a conventional or plasma gasification process.

C,MSW (-35to35)-G

Central Municipal Solid Waste Gasification, feedstock varying from revenues to cost

The system is modeled as a 150 TPD MSW-to-hydrogen plant capital cost of \$126M (total depreciable cost) and 65% efficiency based on information from an un-named industrial company. The assumed technology was not specified but is assumed to be either a conventional or plasma gasification process.

9.3 Appendix C – Terminal Process Flow Diagrams

Database Sheet: GH2 to GT

Database Sheet: GH2 to HPGT

Database Sheet: GH2 to CryoGT

Database Sheet: GH2 to LT

Database Sheet: GH2 to PL

Database Sheet: GH2 to PL to CryoGT

9.4 Appendix D – Dispensing Process Flow Diagrams

Database Sheet: 0.1TPD(GT)

Database Sheet: 1.5TPD (HPGT)

Database Sheet: 1.5TPD (CryoGT)

Database Sheet: 0.1TPD (LT)

Database Sheet: 1.5TPD (LT)

Database Sheet: 1.5TPD (PL)

Database Sheet: 0.1TPD (FC)

Database Sheet: 1.5TPD (FC)

9.5 Appendix E – Dispensing Cost Parameters

The next four tables list the cost and size parameters used at each of the dispensing station options that are available in the HyPro database. References for each of the values are listed in the database in the reference column of each worksheet.

Engineering Assumptions		0.1 TPD (GT) [4,1,1,1]		1.5 TPD (HPGT) [4,2,1,1]	
Truck	(Component,CY)	2005	2020	2005	2020
[deg. C]	Temperature	25	25	25	25
[atm]	Maximum Pressure	180	180	476	476
[atm]	Minimum Pressure	15	15	15	15
[\$]	GT Trailer	\$450,000.00	\$450,000.00	\$700,000.00	\$700,000.00
Dispensers	(Component,CY)	2005	2020	2005	2020
[atm]	Maximum Pressure	425	817	425	817
	Quantity	1	1	3	3
[\$/m]	Unit Cost, Dispensers	\$26,880.00	\$26,880.00	\$26,880.00	\$26,880.00
[\$]	Dispensers	\$26,880.00	\$26,880.00	\$80,640.00	\$80,640.00
Dispenser Compressors	(Component,CY)	2005	2020	2005	2020
	Compressibility Factor	1.1367	1.2524	1.1367	1.2524
[#]	(built) Quantity	3	1	3	1
[#]	(needed) Quantity	2	1	2	1
[kgH2/day] (ea.)	Design Flowrate	50	100	750	1,500
[kgH2/day] (ea.)	Average Flowrate	35	70	525	1,050
[#]	Stages	4	4	4	4
[%]	Isentropic Efficiency	65%	80%	65%	80%
[kW] (ea.)	Average Power Req'd	1.7	4.3	15.8	45.3
[\$/(kgH2/hr)] (ea.)	Unit Cost, Dis. Compr.	\$6,300.00	\$6,300.00	\$4,580.00	\$3,000.00
[\$]	Dis. Compr.	\$39,375.00	\$26,250.00	\$429,375.00	\$187,500.00
Storage, GH2	(Component,CY)	2005	2020	2005	2020
[kgH2]	Usable Capacity	38	38	358	358
[\$/kgH2 Usable Capacity]	Unit Cost, Storage	\$818.00	\$591.00	\$818.00	\$355.00
[\$]	Storage	\$31,084.00	\$22,458.00	\$292,844.00	\$127,090.00
Island Safety					
[\$]	Ctrl. & Safety Equip.	\$22,320.00	\$22,320.00	\$22,320.00	\$22,320.00
Storage, LH2	(Component)				
[kgH2]	Usable Capacity				
[\$/kgH2 Usable Capacity]	Unit Cost, LH2 Storage				
[\$]	LH2 Storage				
Pumps	(Component)				
[#]	Quantity				
[kWh/kgH2]	Average Power Req'd				
[\$/(kgH2/hr)] (ea.)	Unit Cost, Pumps				
[\$]	Pumps				
Evaporator					
[\$]	Evaporator				
Real Estate					
[ft2]	Area	5358		9475	
Costs					
Depreciable Capital (Direct)	(Component,CY)	2005	2020	2005	2020
[\$]	Installed Costs	\$569,659.00	\$547,908.00	\$1,525,179.00	\$1,117,550.00

Engineering Assumptions		1.5 TPD (CryoGT) [4,3,1,1]	0.1 TPD (FC) [4,7,1,1]
Truck	(Component,CY)	2020	2005 2020
[deg. C]	Temperature	25	25 25
[atm]	Maximum Pressure	136	20 20
[atm]	Minimum Pressure	15	
[\$]	GT Trailer	\$745,000.00	
Dispensers	(Component,CY)	2020	2005 2020
[atm]	Maximum Pressure	817	425 817
	Quantity	3	1 1
[\$/m]	Unit Cost, Dispensers	\$26,880.00	\$26,880.00 \$26,880.00
[\$]	Dispensers	\$80,640.00	\$26,880.00 \$26,880.00
Dispenser Compressors	(Component,CY)	2020	2005 2020
	Compressibility Factor	1.2524	1.1384 1.2542
[#]	(built) Quantity	1	3 1
[#]	(needed) Quantity	1	2 1
[kgH2/day] (ea.)	Design Flowrate	1,500	50 100
[kgH2/day] (ea.)	Average Flowrate	1,050	35 70
[#]	Stages	4	4 4
[%]	Isentropic Efficiency	80%	65% 80%
[kW] (ea.)	Average Power Req'd	69.8	3.0 6.7
[\$/(kgH2/hr)] (ea.)	Unit Cost, Dis. Compr.	\$3,000.00	\$6,300.00 \$6,300.00
[\$]	Dis. Compr.	\$187,500.00	\$39,375.00 \$26,250.00
Storage, GH2	(Component,CY)	2020	2005 2020
[kgH2]	Usable Capacity	358	80 80
[\$/kgH2 Usable Capacity]	Unit Cost, Storage	\$355.00	\$818.00 \$591.00
[\$]	Storage	\$127,090.00	\$65,068.18 \$47,011.36
Island Safety			
[\$]	Ctrl. & Safety Equip.	\$22,320.00	\$22,320.00 \$22,320.00
Storage, LH2	(Component)		
[kgH2]	Usable Capacity		
[\$/kgH2 Usable Capacity]	Unit Cost, LH2 Storage		
[\$]	LH2 Storage		
Pumps	(Component)		
[#]	Quantity		
[kWh/kgH2]	Average Power Req'd		
[\$/(kgH2/hr)] (ea.)	Unit Cost, Pumps		
[\$]	Pumps		
Evaporator			
[\$]	Evaporator		
Real Estate			
[ft2]	Area	7825	1875
Costs			
Depreciable Capital (Direct)	(Component,CY)	2020	2005 2020
[\$]	Installed Costs	\$1,162,550.00	\$153,643.00 \$122,461.00

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Engineering Assumptions		1.5 TPD (FC) [4,8,1,1]		1.5 TPD (PL) [4,6,1,1]	
Truck	(Component,CY)	2005	2020	2005	2020
[deg. C]	Temperature	25	25	25	25
[atm]	Maximum Pressure	20	20	20	20
[atm]	Minimum Pressure				
[\$]	GT Trailer				
Dispensers	(Component,CY)	2005	2020	2005	2020
[atm]	Maximum Pressure	425	817	425	817
	Quantity	3	3	3	3
[\$/m]	Unit Cost, Dispensers	\$26,880.00	\$26,880.00	\$26,880.00	\$26,880.00
[\$]	Dispensers	\$80,640.00	\$80,640.00	\$80,640.00	\$80,640.00
Dispenser Compressors	(Component,CY)	2005	2020	2005	2020
	Compressibility Factor	1.1384	1.2542	1.1384	1.2542
[#]	(built) Quantity	3	1	3	1
[#]	(needed) Quantity	2	1	2	1
[kgH2/day] (ea.)	Design Flowrate	750	1,500	750	1,500
[kgH2/day] (ea.)	Average Flowrate	525	1,050	525	1,050
[#]	Stages	4	4	4	4
[%]	Isentropic Efficiency	65%	80%	65%	80%
[kW] (ea.)	Average Power Req'd	44.8	99.8	44.8	99.8
[\$/(kgH2/hr)] (ea.)	Unit Cost, Dis. Compr.	\$4,580.00	\$3,000.00	\$4,580.00	\$3,000.00
[\$]	Dis. Compr.	\$429,375.00	\$187,500.00	\$429,375.00	\$187,500.00
Storage, GH2	(Component,CY)	2005	2020	2005	2020
[kgH2]	Usable Capacity	1193	1193	358	358
[\$/kgH2 Usable Capacity]	Unit Cost, Storage	\$818.00	\$355.00	\$818.00	\$355.00
[\$]	Storage	\$976,022.73	\$423,579.55	\$292,844.00	\$127,090.00
Island Safety					
[\$]	Ctrl. & Safety Equip.	\$22,320.00	\$22,320.00	\$22,320.00	\$22,320.00
Storage, LH2	(Component)				
[kgH2]	Usable Capacity				
[\$/kgH2 Usable Capacity]	Unit Cost, LH2 Storage				
[\$]	LH2 Storage				
Pumps	(Component)				
[#]	Quantity				
[kWh/kgH2]	Average Power Req'd				
[\$/(kgH2/hr)] (ea.)	Unit Cost, Pumps				
[\$]	Pumps				
Evaporator					
[\$]	Evaporator				
Real Estate					
[ft2]	Area	5808		5625	
Costs					
Depreciable Capital (Direct)	(Component,CY)	2005	2020	2005	2020
[\$]	Installed Costs	\$1,508,358.00	\$714,040.00	\$825,179.00	\$417,550.00

<u>Engineering Assumptions</u>		0.1 TPD (LT) [4,4,1,1]		1.5 TPD (LT) [4,5,1,1]	
Truck	(Component,CY)	2005	2020	2005	2020
[deg. C]	Temperature				
[atm]	Maximum Pressure				
[atm]	Minimum Pressure				
[\$]	GT Trailer				
Dispensers	(Component,CY)	2005	2020	2005	2020
[atm]	Maximum Pressure				
	Quantity	1	1	3	3
[\$/m]	Unit Cost, Dispensers	\$26,880.00	\$26,880.00	\$26,880.00	\$26,880.00
[\$]	Dispensers	\$26,880.00	\$26,880.00	\$80,640.00	\$80,640.00
Dispenser Compressors	(Component,CY)	2005	2020	2005	2020
	Compressibility Factor				
[#]	(built) Quantity				
[#]	(needed) Quantity				
[kgH2/day] (ea.)	Design Flowrate				
[kgH2/day] (ea.)	Average Flowrate				
[#]	Stages				
[%]	Isentropic Efficiency				
[kW] (ea.)	Average Power Req'd				
[\$/(kgH2/hr)] (ea.)	Unit Cost, Dis. Compr.				
[\$]	Dis. Compr.				
Storage, GH2	(Component,CY)	2005	2020	2005	2020
[kgH2]	Usable Capacity	38		358	
[\$/kgH2 Usable Capacity]	Unit Cost, Storage	\$818.00	\$591.00	\$818.00	\$355.00
[\$]	Storage	\$31,084.00	\$22,458.00	\$292,844.00	\$127,090.00
Island Safety					
[\$]	Ctrl. & Safety Equip.	\$22,320.00	\$22,320.00	\$22,320.00	\$22,320.00
Storage, LH2	(Component)				
[kgH2]	Usable Capacity	1496		4488	
[\$/kgH2 Usable Capacity]	Unit Cost, LH2 Storage	\$70.00	\$70.00	\$50.00	\$50.00
[\$]	LH2 Storage	\$104,720.00	\$104,720.00	\$224,400.00	\$224,400.00
Pumps	(Component)				
[#]	Quantity	2		2	
[kWh/kgH2]	Average Power Req'd	0.33		0.33	
[\$/(kgH2/hr)] (ea.)	Unit Cost, Pumps	\$22,607.00	\$22,607.00	\$29,638.00	\$29,638.00
[\$]	Pumps	\$45,214.00	\$45,214.00	\$59,276.00	\$59,276.00
Evaporator					
[\$]	Evaporator	\$7,920.00	\$7,920.00	\$12,988.00	\$12,988.00
Real Estate					
[ft2]	Area	5689		10899	
Costs					
Depreciable Capital (Direct)	(Component,CY)	2005	2020	2005	2020
[\$]	Installed Costs	\$238,138.00	\$229,512.00	\$692,468.00	\$526,714.00

The next three tables show the component size that was used to determine the total real estate requirements for each of the dispensing stations. These computations are made using the Forecourt Land-Use Calculator created by Matthew Hooks of TIAX LLC. The assumptions may change however at the time of this report version 4 released on September 24, 2007 was the most recent release.

	1.5 TPD (PL)	1.5 TPD (FC)	3.0 TPD (FC)	0.1 TPD (FC)	
Average Daily Demand	1500	1500	3000	100	kg/day
Storage Factor	0.24	0.8	0.8	0.79	
Storage Required	360	1200	2400	79	kg
Storage per Vessel	21.3	21.3	21.3	21.3	kg
Vessel Diameter	16	16	16	16	in
Vessel Length	30	30	30	30	ft
Extra Radius	2	2	2	2	in
Stacked Vessels	6	6	6	6	
Cascade Levels	3	3	3	3	
Effective Diameter	20	20	20	20	in
Cascade Vessel Groups	6	19	38	2	
Total Cascade Vessels	18	57	114	6	
# Cascade Vessel Stacks	3	10	19	2	
LP Storage Requirement	450	450	900	30	kg
LP Required Storage	0	0	0	0	kg
LP Vessel Capacity	126	126	126	126	kg
LP Vessel Width	4	4	4	4	ft
LP Vessel Length	25	25	25	25	ft
Storage Vessel per Stack	2	2	2	2	
LP Vessels Required	0	0	0	0	
# LP Vessel Stacks	0	0	0	0	
Total Storage Length*	5	17	32	3	ft
Total Storage Width*	30	30	30	30	ft
Total Storage Area (no set)	150	500	950	100	ft ²
Baseline Station Length	150	150	150	150	ft
Baseline Station Width	110	110	110	110	ft
Convenience Store Length	50	50	50	50	ft
Convenience Store Width	30	30	30	30	ft
Baseline Storage Length	20	20	20	20	ft
Baseline Storage Width	45	45	45	45	ft
Setback: Wall Opening	25	25	25	25	ft
Setback: Lot Line	5	5	5	5	ft
Setback: Parked Car	15	15	15	15	ft
Additional Setback A (length)	0	0	0	0	ft
Additional Setback B (length)	0	0	0	0	ft
Additional Setback C (width)	0	0	0	0	ft
Additional Setback D (width)	0	0	0	0	ft
Total Storage Length	20	22	37	20	ft
Total Storage Width	45	45	45	45	ft
Overall Station Length	150	152	167	150	ft
Overall Station Width	110	110	110	110	ft
Overall Station Area	16,500	16,683	18,332	16,500	ft ²
Dispensers	3	3	6	1	
Baseline Area (8 dispensers)	16,500	16,500	16,500	16,500	ft ²
Baseline Area (no C-store)	15,000	15,000	15,000	15,000	ft ²
Overall Area Increase	0	183	1,832	0	ft ²
Baseline Dispensers	8	8	8	8	
Area per Additional Disp. Island	2,200	2,200	2,200	2,200	ft ²
TOTAL H2 AREA	5,625	5,808	13,082	1,875	ft²
TOTAL H2 AREA	523	540	1,216	174	m²

	0.1 TPD (GT)	1.5 TPD (HPGT)	1.5 TPD (CryoGT)	
Station Capacity	100	1,500	1,500	kg/day
Storage Factor	0.38	0.24	0.24	
Storage Required	38	360	360	kg
Storage per Vessel	21.3	21.3	21.3	kg
Vessel Diameter	16	16	16	in
Vessel Length	30	30	30	ft
Extra Radius	2	2	2	in
Stacked Vessels	6	6	6	
Cascade Levels	3	3	3	
Effective Diameter	20	20	20	in
Vessel Groups	1	6	6	
Total Vessels	3	18	18	
# Vessels Wide	1	3	3	
Storage Length*	1.7	5.0	5.0	ft
Storage Width*	30	30	30	ft
Storage Area (no set)	50	150	150	ft ²
Baseline Station Length	150	150	150	ft
Baseline Station Width	110	110	110	ft
Convenience Store Length	50	50	50	ft
Convenience Store Width	30	30	30	ft
Baseline Storage Length	20	20	20	ft
Baseline Storage Width	45	45	45	ft
Setback: Wall Opening	25	25	25	ft
Setback: Lot Line	5	5	5	ft
Setback: Parked Car	15	15	15	ft
Tube Trailer Width	15	15	15	ft
Additional Setback A (length)	32	35	20	ft
Additional Setback B (length)	0	0	0	ft
Additional Setback C (width)	0	0	0	ft
Additional Setback D (width)	0	0	0	ft
Total Storage Length	52	55	40	ft
Total Storage Width	45	45	45	ft
Overall Station Length	182	185	170	ft
Overall Station Width	110	110	110	ft
Overall Station Area	19,983	20,350	18,700	ft ²
Baseline Area (8 dispensers)	16,500	16,500	16,500	ft ²
Baseline Area (no C-store)	15,000	15,000	15,000	ft ²
Overall Area Increase	3,483	3,850	2,200	ft ²
Dispensers	1	3	3	
Baseline Dispensers	8	8	8	
TOTAL H2 AREA	5,358	9,475	7,825	ft²
TOTAL H2 AREA	498	881	727	m²

	0.1 TPD (LT)	1.5 TPD (LT)	
Station Capacity	300	1,500	kg/day
Truck Delivery	1,457	4,372	kg
LH2 Storage Required	1,496	4,488	kg
LH2 Density	68.6	68.6	kg/m ³
LH2 Storage Volume	22	65	m ³
LH2 Storage Volume	5,757	17,272	gal
LH2 Storage Vessels	1	1	
Vessel Diameter (Spherical)	4.5	6.0	m
Vessel Diameter (Spherical)	14.7	19.7	ft
Storage Area (no set)	215	387	ft ²
Baseline Station Length	150	150	ft
Baseline Station Width	110	110	ft
Baseline Storage Length	20	20	ft
Baseline Storage Width	45	45	ft
Convenience Store Length	50	50	ft
Convenience Store Width	30	30	ft
C-Store Entry Length	17	17	ft
Setback: Wall Opening	75	75	ft
Setback: Lot Line	50	50	ft
Additional Setback A (length)	25	25	ft
Additional Setback B (length)	30	30	ft
Additional Setback C (width)	5	5	ft
Additional Setback D (width)	0	0	ft
Total Storage Length	90	95	ft
Total Storage Width	65	70	ft
Overall Station Length	157	162	ft
Overall Station Width	130	135	ft
Overall Station Area	20,314	21,774	ft ²
Dispensers	1	3	
Baseline Area (8 dispensers)	16,500	16,500	ft ²
Baseline Area (no C-store)	15,000	15,000	ft ²
Overall Area Increase	3,814	5,274	ft ²
Baseline Dispensers	8	8	
TOTAL H2 AREA	5,689	10,899	ft²
TOTAL H2 AREA	529	1,013	m²

9.6 Appendix F – Computing Emissions of Production Plants

There are several resources that can be used to make hydrogen. Each resource and method has a different carbon footprint and it is important to quantify that footprint when evaluating hydrogen infrastructures. To summarize from Figure 18, our analysis considers the following feedstocks; Coal, Natural Gas, Industrial Electricity, Ethanol, Demineralized Water (for Nuclear derived Hydrogen), Biomass and Municipal Solid Waste. Lifecycle emissions are only included for plants which consume natural gas and coal. Lifecycle emissions imply all upstream emissions associated with extracting the feedstock, delivering it to its point of consumption, and consuming it in the hydrogen plant. Electricity can have some lifecycle emissions associated with its production (from natural gas, and coal). However for this analysis, the assumption is that since emissions in the electrical utility sector are already heavily regulated, those emissions are accounted for by the electricity generation plants. Therefore accounting for it in the hydrogen production sector would be double bookkeeping.

9.6.1 Emissions from Natural Gas Feedstocks

Natural gas is used as the primary or secondary feedstock for a reforming process. In our analysis it appears as a primary feedstock in the Natural Gas Steam Methane Reforming plants. As a secondary feedstock it appears in several hydrogen production plants, namely, Ethanol Reforming, Biomass Reforming and Municipal Solid Waste Reforming. We'll quantify the emissions associated with natural gas as a secondary feedstock then build on that to develop the emissions values for natural gas as a primary feedstock.

9.6.1.1 Natural Gas as a Secondary Feedstock

When natural gas is used as a secondary feedstock the upstream activities and their associated emissions are shown in Figure 99.

Global Warming Potentials (GWP) ⁸²	
Activity	g CO ₂ e/ MJ feedstock
Production of NG	
Mfg	0.02
Fuel Consumption	0.48
Flare Combustion	0.15
Methane venting	0.29
Processing	
CO ₂ venting	1.69
Pipeline Transport of NG	
Methane loss	0.1
Total	2.73

Figure 99. Upstream Emissions for Natural Gas

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⁸² Ruether, J., Ramezan, M., and Grol, E., 2005, Life-Cycle Analysis of Greenhouse Gas Emissions for Hydrogen Fuel Production in the United States from LNG and Coal, NETL, DOE/NETL-2006/1227, available at http://www.netl.doe.gov/technologies/hydrogen_clean_fuels/refshelf/pubs/H2_from_Coal_LNG_Final.pdf

These emissions are attributed to Ethanol Reforming, Biomass Reforming and Municipal Solid Waste reforming plants. However in order to use this value for calculating carbon taxes, it is necessary to convert from g CO₂e/MJ feedstock to kg GHGe/kg H₂. That is done with the following equation;

$$GHGEmissions(\frac{kgGHGe}{kgH_2}) = \frac{TotalGWP(\frac{gCO_2e}{MJ}) * \frac{141.9MJ}{kgH_2} * \frac{1kg}{1000g}}{FeedstockEfficiency}$$

where Feedstock Efficiency varies for each plant and is listed as a parameter on each production technology worksheets.

9.6.1.2 Natural Gas as a Primary Feedstock

When natural gas is used as a primary feedstock there are emissions from upstream activities and from consumption of the natural gas to create hydrogen. The emissions associated with the hydrogen production depend on whether CCSD equipment is included in the plant. The emissions from plants with no CCSD are shown in Figure 100.

Global Warming Potentials (GWP) ⁸²	
Activity	g CO ₂ e/ MJ feedstock
Production of NG	
Mfg	0.02
Fuel Consumption	0.48
Flare Combustion	0.15
Methane venting	0.29
Processing	
CO ₂ venting	1.69
Pipeline Transport of NG	
Methane loss	0.1
Steam methane reforming (no CCS)	
Mfg	0.19
Fuel combustion/ C Conv	48.6
Electric Power Consumption	1.87
Total	53.39

Figure 100. Emissions from Natural Gas with no CCSD equipment

Using the previous equation, emissions can be converted to the proper units for our analysis.

When CCSD equipment is part of hydrogen production, the activities and their associated emissions values are those listed in Figure 101.

Global Warming Potentials (GWP) ⁸²	
Activity	g CO ₂ e/ MJ feedstock
Production of NG	
Mfg	0.02
Fuel Consumption	0.48
Flare Combustion	0.15
Methane venting	0.29
Processing	
CO ₂ venting	1.69
Pipeline Transport of NG	
Methane loss	0.1
Steam methane reforming (with CCS)	
Mfg	0.19
Fuel combustion/ C Conv	48.6
Electric Power Consumption	1.87
(CO ₂ capture)	-44.7
CO ₂ Compression	2.6
Total	13.8

Figure 101. Emission from Natural Gas with CCSD equipment

There are two additional activities in a plant with CCSD, namely CO₂ capture and compression. GWP for CO₂ capture is negative because that amount of CO₂ equivalents is not released into the environment. In HyPro we assume that CO₂ removal is 92% thus, 92% of the Fuel combustion GWP is contained for disposal. Compression requires additional energy which we assume comes from natural gas since it is already available on site.

Again to compute GHG equivalent emissions we would use the equation provided at the beginning of this appendix. The CO₂ capture value can be converted with the equation below. This value is necessary since the CCSD equipment size and capital costs are based on the quantity of CO₂ that is collected for disposal.

$$CapturedCO_2\left(\frac{kgCO_2}{kgH_2}\right) = \frac{CO_2Capture\left(\frac{gCO_2e}{MJ}\right) * \frac{141.9MJ}{kgH_2} * \frac{1kg}{1000g}}{FeedstockEfficiency}$$

In HyPro, since feedstock efficiency changes as technology improvements occur, we use the average value to compute the captured CO₂. GHG emissions will vary over the analysis period in accordance to feedstock efficiency.

9.6.2 Emissions from Coal Feedstocks

Coal is used as the primary feedstock in the coal gasification plants options. Emissions from using coal as a feedstock are the highest of any other feedstock. For this reason, in our

analysis, there is a prohibition on building Coal gasification plants with no sequestration in California. Since California already has a constraining policy on coal energy plants this assumption seems reasonable. Nevertheless, the state of California will accept the finished product (electricity or hydrogen) from a non-sequestered coal plant located outside the state boundaries. We'll quantify the emissions associated with natural gas as a secondary feedstock then build on that to develop the emissions values for natural gas as a primary feedstock. Thus the emissions of both cases need to be quantified, and similar to natural gas, emissions associated with hydrogen production using coal depend on whether CCSD equipment is included in the plant.

The emissions from plants with no CCSD are shown in Figure 102.

Global Warming Potentials (GWP) ⁸²	
Activity	g CO ₂ e/ MJ feedstock
Coal Mining	
Underground mined, no CCM mitigation	6.4
Mine Development	1.4
Coal Transport	
By Rail	0.54
Conversion of coal to H ₂ (no CCSD)	
Mfg / Construction Activities	0.33
Coal consumption	90
(Electric Power Consumption)	-11.6
Total	87.1

Figure 102. Emissions from Coal Gasification plants with no CCSD equipment

These emissions are attributed to coal gasification plants with no CCSD equipment, namely the regional plants for our baseline scenario of Los Angeles. The emissions associated with Electric Power Consumption are negative because electrical power is created rather than consumed as byproduct of gasification. The emissions resulting from power generation are removed from this account and debited to the electric utility sector's emission account since all surpluses will be sold to the electrical grid. Again it is necessary to convert from g CO₂e/MJ feedstock to kg GHGe/kg H₂ in order to calculate carbon taxes. This is done with the following equation;

$$GHGEmissions\left(\frac{kgGHGe}{kgH_2}\right) = \frac{TotalGWP\left(\frac{gCO_2e}{MJ}\right) * \frac{141.9MJ}{kgH_2}}{FeedstockEfficiency} * \frac{1kg}{1000g},$$

where Feedstock Efficiency varies for each plant and is listed as a parameter on each production technology worksheets.

When CCSD equipment is part of hydrogen production, the activities and their associated emissions values are those listed in Figure 103. There are two additional activities in a plant with CCSD, namely CO₂ capture and compression. GWP for CO₂ capture is negative because that amount of CO₂ equivalents is not released into the environment. In HyPro we assume that CO₂ removal is 92% thus, 92% of the Fuel combustion GWP is contained for disposal. Compression requires additional energy which we assume comes from the coal since it is already available on site.

Global Warming Potentials (GWP) ⁸²	
Activity	g CO ₂ e/ MJ feedstock
Coal Mining	
Underground mined, with CCM mitigation	2.5
Mine Development	1.4
Coal Transport	
By Rail	0.54
Conversion of coal to H ₂ (no CCSD)	
Mfg / Construction Activities	0.4
Coal consumption	94
(Electric Power Consumption)	-3.7
(CO ₂ capture)	-86.5
CO ₂ Compression	6.4
Total	15.1

Figure 103. Emissions from Coal Gasification plants with CCSD equipment

Again to compute GHG equivalent emissions we would use the equation provided earlier in this section. The CO₂ capture value can be converted with the equation below. This value is necessary since the CCSD equipment size and capital costs are based on the quantity of CO₂ that is collected for disposal.

$$CapturedCO_2\left(\frac{kgCO_2}{kgH_2}\right) = \frac{CO_2Capture\left(\frac{gCO_2e}{MJ}\right) * \frac{141.9MJ}{kgH_2}}{FeedstockEfficiency} * \frac{1kg}{1000g}$$

In HyPro, technology improvements in coal gasification are treated as separate technologies since equipment changes are required. Thus the GHG emissions and captured CO₂ values are specific to a coal gasification plant using a given technology.

9.7 Appendix G – Cumulative CO₂ Emissions Calculations

Transitioning light duty vehicles (LDV) to operate on hydrogen has many implications not only on the vehicles but also on net emissions emitted from the transportation sector. The HyPro model determines the most economic ways for this transition to occur considering different hydrogen production, delivery, and dispensing options. The primary city of studied has been Los Angeles because of its large population and its location in California, a state which has been a driving force in this transition to cleaner energy solutions. The hydrogen demand based for LDV in Los Angeles is shown in Figure 47. This curve and a few basic assumptions provide all the data need to calculate the emissions contributions from both gasoline vehicles and hydrogen production stations.

9.7.1 Emissions from Hydrogen Production Facilities

Based on the demand in Figure 47, HyPro selects the infrastructure shown in Figure 49. Forecourt SMR plants of size 1.5 TPD are selected in all years of the analysis. These plants emit between 9 and 11 kg CO₂/kgH₂ produced depending on the analysis year (efficiency improvements also affect emissions). Each of these plants has a 20-year lifetime. In order to arrive at the emissions of the infrastructure, one must compute the emissions of a single plant, emissions of a new year's build and cumulative emissions in a given year.

The emissions associated with a single plant are;

$$SglPlant :CO_2(kg) = \frac{kgCO_2}{kgH_2} * \frac{PlantCapacity(TPDH_2)}{TPD / 1000kg} * PlantCapacityFactor$$

Knowing the emissions of a single plant, the new year's build emissions are;

$$NewBuilds :CO_2(kg) = CO_2(kg)_{SglPlantA} * QtyBuilt_A + CO_2(kg)_{SglPlantB} * QtyBuilt_B$$

A and B in the equation above are different types of plants. In most instances HyPro selects just one type of plant for a given year, however there are instances where 2 types of plants result in the lowest cost pathway. Knowing the emissions associated with each build year and the lifetime of the plants, the cumulative emissions for a given year are;

$$CumulativeCO_2(Year_i) = CO_2(Year_{i-1}) + CO_2(NewBuilds)_i - CO_2(PlantsDecommissioned)_i$$

This summation is graphically represented in Figure 54; however an excerpt of the tabular data is shown in Figure 104. As the demand for hydrogen increase so do the emissions from the hydrogen production. This increase in emissions is countered by a decrease in emission from gasoline vehicles that are being replaced.

Year	2012	2016	2017	2018	
Production Plant	FC,NG-SMR,1.5 (LCLB)	FC,NG-SMR,1.5 (LCLB)	FC,NG-SMR,1.5 (LCLB)	FC,NG-SMR,1.5 (LCLB)	
Qty	40	19	45	56	
Emissions (kg/ kg H2)	10.23	10.02	9.96	9.90	
Plant Capacity (TPD)	1.50	1.50	1.50	1.50	
Plant Efficiency (%)	70%	70%	70%	70%	
Lifetime	20	20	20	20	
Calculate - New CO2 Emissions (TPD)	429.52	199.95	470.58	581.90	
Year	Cum CO2				
2012	429.52	0.00	0.00	0.00 ...	429.52
2016	429.52	199.95	0.00	0.00 ...	629.47
2017	429.52	199.95	470.58	0.00 ...	1100.05
2018	429.52	199.95	470.58	581.90 ...	1681.95
2019	429.52	199.95	470.58	581.90 ...	2384.03
2020	429.52	199.95	470.58	581.90 ...	3132.90
2021	429.52	199.95	470.58	581.90 ...	3927.89
2022	429.52	199.95	470.58	581.90 ...	4788.59
2023	429.52	199.95	470.58	581.90 ...	5683.90

Figure 104. Cumulative Emissions Table

9.7.2 Emissions from Gasoline Vehicles

In computing the emissions for gasoline cars we make an important assumption that the total city population and the vehicle/person ratio are constant in all analysis years. This assumption is stated in Section 5.3.2 of the report. Thus, the number of gasoline vehicles in any given year is;

$$GasCars : QtyGasCars = (Population * \frac{Vehicles}{Person}) - (\frac{H_2 Demand (tpd)}{LDVH_2 Use (kg / day)} * \frac{1000kg}{1t})$$

where LDVH₂Use is the consumption of hydrogen per light duty vehicle. This is determined by;

$$LDVH_2 Use (kg / day) = \frac{Mi / yr / Vehicle}{MPG (H_2 Vehicles)} * \frac{yr}{365 days} * \frac{LHV Gas (gallon)}{LHVH_2 (kg)}$$

where 0.122 is used for the LHV of a gallon of gasoline and the LHV of a kilogram of H₂ is 0.127. The other terms in the equation are defined in Section 5.3.2.

Knowing the number of gasoline and hydrogen cars out on the road in any given year allows us to compute the emissions from each group. In the case of hydrogen fueled cars, no emissions are recorded as part of driving the vehicle. All emissions with this group are associated with hydrogen production and were computed earlier in this appendix. In the case of gasoline cars we need to compute the amount of CO₂ emitted when gasoline fuel is burned. Research indicated that 19.564 lbs of CO₂ are emitted for every gallon of gasoline.⁸³ Thus the daily CO₂ emissions in a given year from gasoline vehicles with the efficiency of 24.6 MPG are;

⁸³ "Fuel and Energy Source Codes and Emission Coefficients." EIA Voluntary Reporting of Greenhouse Gases Program. <http://www.eia.doe.gov/oiaf/1605/factors.html>.

$$VehCO_2Emissions(tpd) = \left(\frac{19.564lbsCO_2}{gal} * \frac{Mi / yr / Vehicle}{24.6MPG(GasVehicles)} * \frac{1t}{2200lbs} * \frac{1yr}{365days} \right)$$

$$CO_2Emissions(tpd)_{GasVeh} = QtyGasCars * VehCO_2Emissions$$

The emissions from hydrogen production plants when compared with those of the gasoline vehicles are much lower on a yearly basis. This is shown in Figure 55 of this document by the decreasing value of the cumulative emissions series on the chart. So the baseline infrastructure although it is optimized for cost begins to address the emissions concerns of the transportation sector.

9.8 Appendix H - Feedstock Consumption Check

Transitioning light duty vehicles (LDV) to operate on hydrogen has many implications not only on the vehicles but also on the fuel supply infrastructure. The HyPro model determines the most economic ways for this infrastructure to occur considering different hydrogen production, delivery, and dispensing options. The primary city of studied has been Los Angeles because of its large population and its location in California, a state which has been a driving force in this transition to cleaner energy solutions. Looking at Los Angeles' hydrogen demand based on LDV, HyPro suggests the baseline build-out shown in Figure 105. This scenario assumes California's current coal policy, which does not allow unsequestered Coal to Electricity plants, will also apply in the case of Coal to Hydrogen plants. No other constraints, taxes, or subsidies are included in the analysis. Figure 105 shows the forecourt natural gas steam methane reforming plant is the most economic solution at all demand levels. With no government interaction, the hydrogen infrastructure would be based on natural gas.

Figure 105. Los Baseline Build - Lower bound SMR Enabled

As mentioned in the body of this report, although the U.S. has natural gas reserves, it relies on foreign production for its current demand. Thus it would appear that having the transportation sector depend on this raw material would only further our dependency on foreign resources. Research on natural gas resources is summarized below.

9.8.1 Natural Gas Resources

"The U.S. has 204 trillion cubic feet of natural gas reserves (about a ten-year supply at current rates of usage), and there are an estimated 656 trillion cubic feet of undiscovered but recoverable natural gas in U.S. territory...."⁸⁴ The U.S. reserves of natural gas make up

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⁸⁴ Hayward, Steve. "Questions and Answer". The American, MAY/JUNE 2007 p. 90 – 95.

only 3% of the world reserves.⁸⁵ The U.S. reserves are consumed both nationally and internationally through exportation. The net U.S. imports equaled approximately 15 percent of all domestic demand, implying that we supply 85% of our own natural gas. Data indicates that relationship has remained relatively constant since 1999.⁸⁶ The consumption rates for the country and California are shown in Figure 106.⁸⁵ We only produce about 25% of the oil we consume.⁸⁴ Thus, using natural gas as opposed to oil for LDV is encouraging.

Trillion Cubic Feet	2001	2002	2003	2004	2005	2006
U.S. Consumption	22.2	23.0	22.3	22.4	22.2	21.8
California	2.5	2.3	2.3	2.4	2.2	2.5

Figure 106. Natural Gas Consumption⁸⁵

Confirming that our switch from oil to hydrogen will not result in a dependency on foreign resources addresses only part of the concern. We still need to quantify how much additional natural gas is needed to support the proposed hydrogen infrastructure and determine whether that is possible given our knowledge of the resources available. Below is the computation method used in this study to determine the amount of natural gas required to support this hydrogen infrastructure.

9.8.2 Hydrogen's Feedstock Requirement

In order to calculate the feedstock requirement we follow a four-step process. The first step is to determine the amount of feedstock required for a plant's daily hydrogen production rate. Then we compute the yearly requirement for the plant. Next, knowing the quantities of plants built we determine the annual requirement of the build. Lastly, since each plant's lifetime extends beyond one calendar year, we sum the annual requirement of one build with that of previous years' builds in a given calendar year to compute the feedstock requirement for a given demand. Since our goal is to assess the impact of the baseline build-out scenario on the natural gas resource, we conservatively assume that all plants are operating at full utilization since that is the point at which the most natural gas would be consumed.

The build-out in Figure 105 shows only 1 type of plant is selected, 1.5 TPD forecourt SMR plant using natural gas. To compute the feedstock required, the data in Figure 107 is required. Additionally, constants and conversion factors required are shown in Figure 108.

Production Method	Plant Size (TPD)	Lifetime (yrs)	Capacity Factor	Feedstock Efficiency (GJ H ₂ /GJ NG)
Forecourt SMR	1.5	20	70%	0.75

Figure 107. Hydrogen Production Plant Data

Natural Gas	1	Nm ³ =	0.0366	GJ
Hydrogen	1	kg =	0.119	GJ (LHV)
Volume Conversion	1	Nm ³ =	35.3	scf
Trillion (Scf)	1E12	scf		

⁸⁵ EIA in 2000 (<http://www.naturalgas.org/overview/resources.asp>).

⁸⁶ U.S. Natural Gas Imports and Exports: 2004 - Energy Information Administration/Office of Oil and Gas, December 2005, http://www.eia.doe.gov/pub/oil_gas/natural_gas/feature_articles/2005/ngimpexp/ngimpexp.pdf

Figure 108. Conversion Parameters

Before embarking on the calculations we make two simplifying assumptions. First we assume that the plant is fully utilized through its life so the capacity factor remains constant. Second, the feedstock efficiency doesn't change during the plant lifetime.

As mentioned previously, the first step is to determine the amount of feedstock required for a plant's daily hydrogen production rate. Begin with hydrogen production capacity and apply the capacity factor and feedstock efficiency to determine the amount of feedstock required in the equation below.

$$NG(\frac{scf}{day}) = PlantSize(\frac{ton}{day}) * \frac{1000kg}{ton} * CapacityFactor * \frac{0.119GJH_2}{1kg} ...$$

$$* \frac{1}{FeedstockEfficiency} (\frac{GJNG}{GJH_2}) * \frac{1Nm^3}{0.0366GJNG} * \frac{35.3scf}{1Nm^3}$$

Then we compute the yearly requirement for the plant.

$$NG(\frac{scf}{yr})_{yearly} = NG(\frac{scf}{day}) * 365 \frac{days}{yr}$$

Next, one determines the annual requirement of the build-out from the quantity of plants built in a given year. Those quantities are available in Figure 105 (suppressed here for clarity) or in the Capital Cost table. An excerpt of the necessary data from the capital cost table is shown in Figure 109.

$$NG(\frac{scf}{yr})_{annual} = NG(\frac{scf}{yr})_{yearly} * QtyBuilt$$

Year	Production Plant	Qty	Year	Production Plant	Qty
2012	FC,NG-SMR,1.5 (LCLB)	40	2033	FC,NG-SMR,1.5 (LCLB)	299
2016	FC,NG-SMR,1.5 (LCLB)	19	2034	FC,NG-SMR,1.5 (LCLB)	293
2017	FC,NG-SMR,1.5 (LCLB)	45	2035	FC,NG-SMR,1.5 (LCLB)	282
2018	FC,NG-SMR,1.5 (LCLB)	56	2036	FC,NG-SMR,1.5 (LCLB)	283
2019	FC,NG-SMR,1.5 (LCLB)	68	2037	FC,NG-SMR,1.5 (LCLB)	286
2020	FC,NG-SMR,1.5 (LCLB)	73	2038	FC,NG-SMR,1.5 (LCLB)	271
2021	FC,NG-SMR,1.5 (LCLB)	78	2039	FC,NG-SMR,1.5 (LCLB)	256
2022	FC,NG-SMR,1.5 (LCLB)	85	2040	FC,NG-SMR,1.5 (LCLB)	236
2023	FC,NG-SMR,1.5 (LCLB)	89	2041	FC,NG-SMR,1.5 (LCLB)	216
2024	FC,NG-SMR,1.5 (LCLB)	107	2042	FC,NG-SMR,1.5 (LCLB)	200
2025	FC,NG-SMR,1.5 (LCLB)	115	2043	FC,NG-SMR,1.5 (LCLB)	185
2026	FC,NG-SMR,1.5 (LCLB)	166	2044	FC,NG-SMR,1.5 (LCLB)	186
2027	FC,NG-SMR,1.5 (LCLB)	192	2045	FC,NG-SMR,1.5 (LCLB)	180
2028	FC,NG-SMR,1.5 (LCLB)	219	2046	FC,NG-SMR,1.5 (LCLB)	218
2029	FC,NG-SMR,1.5 (LCLB)	244	2047	FC,NG-SMR,1.5 (LCLB)	234
2030	FC,NG-SMR,1.5 (LCLB)	266	2048	FC,NG-SMR,1.5 (LCLB)	253
2031	FC,NG-SMR,1.5 (LCLB)	284	2049	FC,NG-SMR,1.5 (LCLB)	272
2032	FC,NG-SMR,1.5 (LCLB)	334	2050	FC,NG-SMR,1.5 (LCLB)	287

Figure 109. Production Units built by year

Lastly, since each plant's lifetime extends beyond one calendar year, we sum the annual requirement of one build with that of previous years' builds in a given calendar year to compute the feedstock requirement for a given demand.

$$NG_{Year1}(\frac{scf}{yr}) = \sum NG(\frac{scf}{yr})_Z + NG(\frac{scf}{yr})_{Z-1} + \dots + NG(\frac{scf}{yr})_{YearStart}$$

This summation is graphically represented in Figure 110. The computed feedstock requirement for Los Angeles in all years is summarized in Figure 111.

Year	2012	2016	2017	2018	2019	2020
Production Plant	FC,NG-SMR,1.5 (LCLB)	FC,NG-SMR,1.5 (LCLB)	FC,NG-SMR,1.5 (LCLB)	FC,NG-SMR,1.5 (LCLB)	FC,NG-SMR,1.5 (LCLB)	FC,NG-SMR,1.5 (LCLB)
Year	Feedstock Consumption					
2012	0.0023	-	-	-	-	-
2013	0.0023	-	-	-	-	-
2014	0.0023	-	-	-	-	-
2015	0.0023	-	-	-	-	-
2016	0.0023	0.0011	-	-	-	-
2017	0.0023	0.0011	0.0026	-	-	-
2018	0.0023	0.0011	0.0026	0.0033	-	-
2019	0.0023	0.0011	0.0026	0.0033	0.0040	-
2020	0.0023	0.0011	0.0026	0.0033	0.0040	0.0043
2021	0.0023	0.0011	0.0026	0.0033	0.0040	0.0043
2022	0.0023	0.0011	0.0026	0.0033	0.0040	0.0043
2023	0.0023	0.0011	0.0026	0.0033	0.0040	0.0043
2024	0.0023	0.0011	0.0026	0.0033	0.0040	0.0043
2025	0.0023	0.0011	0.0026	0.0033	0.0040	0.0043
2026	0.0023	0.0011	0.0026	0.0033	0.0040	0.0043
2027	0.0023	0.0011	0.0026	0.0033	0.0040	0.0043

Figure 110. Summation of Annual Feedstock Requirements

Annual NG Resource Required (Trillions SCF)	
Year	Baseline Build-out
2012	0.0023
2013	0.0023
2014	0.0023
2015	0.0023
2016	0.0035
2017	0.0061
2018	0.0094
2019	0.0134
.	.
.	.
.	.
2049	0.2952
2050	0.2965

Figure 111. Additional natural gas feedstock required for LA LDV

Figure 112. Annual LA LDV NG Resources Required

9.8.3 Relating Natural Gas Consumption Rates

The maximum rate of consumption is 0.2965 trillion SCF in year 2050 of the build in Figure 105. These requirements are only for Los Angeles LDVs however the natural gas consumption rates we have are for the state of California. Thus we must relate the Los Angeles analysis to California. The natural gas demand for Los Angeles is based on the criteria in Figure 113. U.S. Census bureau provides population information for California as stated in Figure 113. Thus, if we assume that the vehicle to person ratio is constant throughout the state, Los Angeles has approximately 32% of the state's LDV, and thus the entire state's feedstock requirement from LDV would be 0.917 trillion SCF. Comparing to the California consumptions in Figure 113, a quick calculation indicates that the expected additional natural gas required would be 39% of the current natural gas consumption rates. While this is a significant amount, it occurs over 40 years and may be dwarfed by additional consumption from other sources such as population growth. More importantly, we have proven that the natural gas requirement due to the transition to Hydrogen using SMR production technology doesn't require more resources than are currently available or being used.

	2001	2002	2003	2004	2005	2006
US Population	285,226,284	288,125,973	290,796,023	293,638,158	296,507,061	299,398,484
California Population	34,550,466	35,024,517	35,466,365	35,841,254	36,154,147	36,457,549
Los Angeles Population					11,789,487	
LA Vehicle / Person Ratio					0.69	
LA Vehicles					8,134,746	
LA/CA Ratio	34.12%	33.66%	33.24%	32.89%	32.61%	32.34%

Figure 113. California Population per U.S. Census Bureau

9.9 Appendix I – HyPro Model User's Manual

9.9.1 Overview

The HyPro software uses Excel for user input interface and MatLab for the user analysis interface. All inputs are done at the cell level in Excel. The analysis requires the MatLab software, and knowledge of a few basic HyPro specific commands. Results are provided in both MatLab and Excel for further study.

This manual will provide the software user with;

- a basic understanding of how the Excel database is structured,
- a brief description of the HyPro software suite,
- a description of the necessary conditions for the software to interact with the database,
- the HyPro commands for the completing analysis and displaying results
- explanation of results provided,
- the basic MATLAB figure commands used in depicting and studying results, and
- suggestions for organizing and archiving results.

9.9.2 Input data

All user inputs should be made in the Excel spreadsheets' worksheets. The worksheets are color coded system to facilitate data entry. The color system is summarized in Figure 114.

Input Database Color Scheme		
	Gray	Commands to the MatLab compiler that parses the database
	Blue	User entered numbers; read directly into MatLab
	Orange	Calculations; read directly into MatLab
	Yellow	User entered numbers; not read directly into MatLab
	Green	Calculations; not read directly into MatLab
	Purple	Off sheet reference; may or may not be read directly into MatLab
	Brown	Reference cell for values and equations

Figure 114. Database Color Scheme

Each production, terminal, delivery and dispensing option is characterized on its own worksheet in the database. Variable names are listed in Column B and are fixed. Column A notifies MatLab what type of variable it is receiving. Column C gives the user the units for the numerical value. All user modifications should be made in Column E or greater. Figure 115 depicts how a central production option is characterized.

Figure 115. Production Technology Worksheet

Some typical modifications include adding a carbon tax, changing the demand or city, improving efficiency, and updating a capital equipment cost. Less common modifications are modification of IRR, accounting for a cost credit and recalculating depreciable capital. All of these can be done and their impact assessed. Figure 116 describes some typical user modifications and where those modifications can be made.

Modifications	Sheet Name	Cell Reference
Demand	LA (or another city name)	Rows 5 – 12
Tax Rate		E4
City Size		E13
Minimum Station Spacing		E19
Analysis Start / Stop years	Global	E2 & E3
Feedstock Costs		Rows 7 – 26
Emission Taxes		Rows 52 - 58
Turning option on/off	All Production Sheets	A1
IRR		E7
Analysis Period		E9
Capacity Factor		E14
Location		E15
Efficiency		Rows 60 – 79

Modifications	Sheet Name	Cell Reference
Overhead, Contingencies		Rows 32 – 53
Emissions		Rows 94 – 100
Learning factor		Rows 104 -108
Turning option on/off	All Terminal Sheets	A1
IRR		E7
Analysis Period		E9
Capacity Factor		E14
Depreciable Capital		Row 192 - 193
Turning option on/off	All Delivery Sheets	A1
IRR		E7
Analysis Period		E9
Capacity Factor		E14
Unit Costs		Rows 34 -35 (trucks), Rows 19, 37 (pipeline)
Turning option on/off	All Dispensing Sheets	A1
IRR		E7
Analysis Period		E9
Capacity Factor		E14
Depreciable Capital		Row 54
Rent		Row 66

Figure 116. Commonly adjusted Input Fields

9.9.3 HyPro model

The HyPro model is made of up several MatLab M-files, each of which is capable of a different portion of the total analysis. The complete list of these subroutines and a quick description of the functions they perform are shown in Figure 117. The run files are designated by the all caps naming scheme.

Subroutine Name	Function Description
LOADEXCEL*	<i>Command to call CompileDatabase</i>
CompileDatabase	<i>Loads Excel database into MATLAB</i>
ParseSheet(internal)	<i>Loads Excel data from an individual sheet</i>
DoOClass(internal)	<i>Assigns numbers to sheets with OClass(3)<0</i>
GetPaths	<i>Builds all supply chain paths</i>
BuildPath (internal)	<i>Recursive function called by GetPaths to build all supply chain paths</i>
RUNSIM*	<i>Command to call MainLoop.m</i>
MainLoop	<i>Simulates a loaded Excel database</i>
Rewrite	<i>For an individual bidding round, determines prices of new facilities and prices and available capacities of existing capacities</i>
GetDelCap	<i>Determines delivery capacities; this is only really interesting for shared delivery methods such as liquid truck</i>
type_quantity (internal)	<i>Determines quantities (or utilizations) of terminal and delivery supply chain components</i>
cost_all (internal)	<i>For a given I,J IClass, determines bids for new and existing capacity, selects the lowest bid, and determines capacity available at that bid (infinite for new capacity)</i>
Cost	<i>Determines costs (bids) for a given sheet</i>
insert_in_next (internal)	<i>Called at the end of a bidding round to add capacity of</i>

Subroutine Name	Function Description
	<i>winning bid to the next turn's available existing capacity</i>
add_to_totals (internal)	<i>Called at the end of a bidding round to add capacity of winning bid to the current turn's running total of allocated capacity</i>
determine_uti (internal)	<i>Called at the end of a turn to determine actual load balanced utilization of supply chain members</i>
SHOWBUILDOUT*	<i>Command to call TieDye</i>
TieDye	<i>Shows TieDye plot</i>
SHOWROUNDS*	<i>Command to call PricePlot</i>
PricePlot	<i>Plots price data for each pathway as a function of year. Errorbars show range in prices across individual bidding rounds within a given year</i>
convert_costs (internal)	<i>Reformats individual bidding round cost data output from MainLoop.m into a format suitable for errorbar plot</i>
SHOWSTATIC*	<i>Commands to call PricePlot2 (SHOWSTATIC shows 10 lines)</i>
SHOWSTATIC_SGL*	<i>Commands to call PricePlot2 (SHOWSTATIC shows 1 line)</i>
PricePlot2	<i>Plots static price approximation for each pathway as a function of year</i>
DispPath	<i>Prints out sheet names for components of a given pathway</i>
DispStatic	<i>Displays breakdown of static price approximation for a given pathway and year</i>
DemandGen	<i>Tool for generating demand curves</i>
minON	<i>Tool for generating demand curves</i>
minON2	<i>Tool for generating demand curves</i>
CapCostFromPathway	<i>Tabulates into Excel the capital cost of each option selected in the build out</i>
ListAllPaths	<i>Prints out sheet names for components of a given pathway, for all pathways</i>
WriteAllPaths	<i>Prints out into Excel the breakdown of static price approximation for each pathway and all years</i>

*These are executable run files.

Figure 117. Subroutine Descriptions

9.9.4 Requirements to run HyPro

In order to run HyPro there are certain conditions which must be satisfied. These are;

1. Complete model code must be placed together in folder where analysis will be performed.
2. Excel workbook needs to be placed in same folder and renamed to 'loaddata.xls'. MatLab is case sensitive so file name during analysis must be exact.
3. MatLab v7.1 should be installed on the computer or server where analysis will take place.

9.9.5 HyPro Commands in MATLAB

9.9.5.1 Analysis

To begin we need to open up MatLab either through the startup menu under programs or through a desktop shortcut. The default start window is shown in Figure 118. Make sure that the current directory is set to folder that has HyPro software suite. This can be done from the browse feature on the toolbar or via the command line in the command window.

>> cd 'Revised Code 11-July-2007 for Learning Curve'

Figure 118. MatLab Interface

The first command in running the code is LOADEXCEL. Type this in the command line and press enter.

>> LOADEXCEL

This subroutine reads the Excel workbook and places the proper values in the named arrays. This step is the longest and can take up to 10 minutes depending on the number of production options available for the analysis. Note that placing a '-1' in cell A1 (of an Excel worksheet) would result in option or sheet being skipped over by MatLab thereby reducing the run time for this subroutine. This modification can be used when looking at a more specific study. The typical output to the command window is shown in Figure 119. If there is an error in the database this subroutine will send an error message to the screen and abort compiling. Should this occur, correct the error in Excel and resave the file. Before reloading the database use the Matlab command, *clear all*, to ensure no faulty values have been saved in arrays. Once the information is successfully loaded, MatLab will provide elapsed time and return the command line. At this point the analysis can begin.

Figure 119. MatLab Command Window

On the command line, type RUNSIM and press enter. This is the workhorse subroutine which applies the demand to the different options, calculates the cost of each pathway determines the minimum price and stores options into a winning pathway array.

>> RUNSIM

If there is an error, check the demand field in the input worksheet. The demand needs to be constant or increasing over time. HyPro cannot evaluate a condition where the demand decreases over any point in time. Once the simulation is complete, MatLab will provide elapsed time and return the command line. At this point the analysis is complete and user can proceed to review results.

9.9.5.2 Results

The first sets of results are the winning pathways. At the command line type, SHOWBUILDOUT then press enter.

>>SHOWBUILDOUT

To the prompt, "enable new plant production numbers? (y/n):" answer 'n'. A response of 'y' will result in the number of units built superimposed on the graph making it difficult to read.

Four figures will appear (see Figure 120). Window names will always default to;

- Figure 1, for the production components
- Figure 2, for the terminal components
- Figure 3, for the delivery components
- Figure 4, for the dispensing components

In the case that no remote facilities are selected as part of the winning pathways, Figures 2 and 3 will be blank. Figures will have a chart title, Buildout (Pro.), Buildout (Term.), Buildout (Del.), or Buildout (Disp.) for Production, Terminal, Delivery and Dispensing, respectively. All figures plot volume (on the Y-axis) vs. calendar year (on the X-axis). Volume is expressed in tons per day (TPD) in all cases except for truck delivery, where it is expressed as number of units. All figures will have a legend. The legend will include the symbols for Capacity and Demand, a box and 'x' respectively.

Figure 120. Raw Infrastructure Build out Plots

The legend provides information on the winning pathway. The information is displayed as follows;

[COLOR BOX] [YEAR BUILT] [TAB NAME] @ [PATHWAY #] x [# of UNITS]

where,

- [COLOR BOX], an arbitrary color selected by MatLab to represent a pathway in a given year. In subsequent years, pathway does not have the same color.
- [YEAR BUILT], year in which the option was selected as lowest cost option. These are listed in sequential order with the earliest year at the top of the legend. Skipped years indicate that demand in that year has not exceeded supply and thus no new facilities were required. A non-sequential number indicates a reallocation of assets. See more below.
- [TAB NAME], worksheet name from Excel workbook of the option that was selected.
- [PATHWAY #], number assigned to the specific production, terminal, delivery and dispensing combination. This number is unique to the pathway and does not vary from year to year in the same analysis. It will vary from analysis to analysis depending on which options were toggled on/off in the database.

- [# of UNITS], the quantity of units that each column represents. In the case of production, terminal, and dispensing, this is the physical number of plants that are built in that year of the analysis. In the case of truck delivery, # of units signifies the number of trucks required for a given pathway. For pipeline delivery, the # of units are the physical number of miles of pipeline laid down for a given pathway.

All figures are bar charts where the height of the bar represents the volume of supply added. Same color and size bars shown in a variety of years represents the lifetime of the option. For example, forecourt stations are typically good for 20 years, thus if 4 stations are built in 2012, they will remain a supply source for the next 20 years and will not need to be replenished until 2032. If they are replenished by the same option, that new option will be listed on the legend as a build in 2032 and will be differentiated with a different color.

Figure 121. Raw Production Build out Plot

From time to time, the analysis will strand assets because it is more economical than continuing to produce hydrogen with an older, more costly technology. This may or may not be visible by disappearance of a column before its lifetime has expired and a change in the column height of another option. Another place it can be see is in the legend. Reallocation of assets is annotated as;

[COLOR BOX] [YEAR BUILT] [TAB NAME] => [PATHWAY #]

where,

- [COLOR BOX], an arbitrary color selected by MatLab to represent a pathway in a given year. In subsequent years, pathway does not have the same color.
- [YEAR BUILT], year the stranded pathway was built. Looking for a previous entry with the same year in the legend will provide additional details about the pathway.
- [TAB NAME], worksheet name from Excel database of the option that was selected.
- [PATHWAY #], new pathway number which has absorbed the stranded supply.

The next set of results can be seen by entering SHOWSTATIC on the command line followed by the Enter key.

>> SHOWSTATIC

A window named Figure 9 will appear. The line graph plots Cost with Return (on the Y-axis) vs. calendar year (on the X-axis). Each line represents a different pathway. By default the 10 lowest cost pathways in any given year are graphed in Figure 9. This default can be adjusted if necessary. Each pathway is represented by an arbitrarily selected line color and marker. This designation does not vary from year to year but does vary from analysis to analysis depending on which options were toggled on/off in the database and which are the lowest costs. The legend lists every pathway shown in the figure in the format;

[MARKER] [PROD TAB NAME] => [TERM TAB NAME] => [DEL TAB NAME] => [DISP TAB NAME]

or, in the case of forecourt production pathways

[MARKER] [PROD TAB NAME] => [DISP TAB NAME]

where,

[MARKER], arbitrary color line and marker assigned by MatLab to that pathway

[PROD TAB NAME], production worksheet name from Excel database that is part of this pathway.

[TERM TAB NAME], terminal worksheet name from Excel database that is part of this pathway.

[DEL TAB NAME], delivery worksheet name from Excel database that is part of this pathway.

[DISP TAB NAME], dispensing worksheet name from Excel database that is part of this pathway.

Figure 122. Calculated Hydrogen cost (with IRR) at pump for cheapest infrastructures

The last set of results is the tabular cost and quantity data of each pathway analyzed. At the command line type,

```
>>WriteAllPaths(mzip_path(:,,:),mtpi_new,rt_CY)
```

then press enter. While processing, MatLab will list the pathway data that it is currently writing to the file. When task is completed, a file named 'AllPaths&Years.xls' will appear in your working directory. If you open this file you will find 8 columns of data on Sheet2. The columns are named;

- Pathway
- Year
- Production
- Terminal
- Delivery
- Dispensing
- TotalCost/kg
- Path Details

The numbers in the Production, Terminal, Delivery, and Dispensing columns are expressed in \$/kg and should sum to the value in the TotalCost/kg column. This data is sorted by ascending pathway and ascending year. The data can be sorted differently and put into Pivot Tables for interpretation.

To determine the overall costs associated with the infrastructure selected by HyPro, at the command line type,

```
>>xlswrite('CapCosts.xls',mxy_depCap)
```

then press enter. When task is completed, a file named 'CapCosts.xls' will appear in your working directory. If you open this file you will find 8 columns of data on Sheet 1. The columns are named;

- Year
- Tech
- Path
- Qty
- DepCap (ea.)
- Learning
- DepCap (total)
- Miles (ea.)

The first 4 columns describe what was built. The next 4 columns provided costs. The cost of the entire infrastructure over the analysis period is the sum of the values in the DepCap (total) column. Miles (ea.) is only used in the case of pipeline pathways.

There may be sensitivities that only require a change in hydrogen demand. Rather than reloading the entire Excel workbook, the variable can be overwritten from the MatLab command window by typing,

```
>>Glo.Demand(:,:)=547500;
```

This sets the demand for all years of the analysis to 547,500 kilograms per year. Recall that the units for this variable are listed in the Excel workbook for the variable Demand on the region worksheet. If the demand is not constant, the command can still be used however the demand for each year must be specified in an array format.

Remember to save results before running next analysis. Also to ensure that no data from previous analysis was kept in MatLab arrays, use the clear all command before each analysis.

```
>>clear all
```

9.9.6 *MatLab Figure Commands*

There are several ways that the MatLab figures can be adjusted to more clearly convey results. The figure windows have 2 toolbars. Symbols in these toolbars are identified in Figure 123.

Figure 123. MatLab figure window toolbar

- Edit Plot

By selecting the Edit Plot tool you can click and drag legend into any position in the figure.

- Insert Legend

Toggling the Insert Legend tool allows you to hide or show the legend.

- Data Cursor

Selecting the data cursor allows you to select a point on the graph and have a temporary comment box pop up which provides x and y value of the point.

Insert Colorbar and Rotate 3D (right of the hand icon) are not useful for these types of charts. If Show Plot Tools is chosen the window will expand and allow for a much larger selection of edits.

- Show Plot tools

The expanded window is shown in Figure 124. The window is divided into four areas.

Figure 124. MatLab figure window expanded with plot tool options

- **Property Editor**

The bottom area, Property Editor allows you to change the window name, in the box titled Figure Name. If you select a point on the plot area, the Property Editor opens up tabs which allow you to adjust axis names, font, range, etc. When the legend is selected its location and font can be adjusted in the Property Editor.

- **Plot Browser**

The plot browser window list all components in the chart area and allows you to toggle them on or off via the check boxes. If a component, say a data series, is selected (not on the check box), the Property Editor displays information for that data series. One can then change the color and type of the line, marker or column, adjust its thickness and rename the data series.

- **Chart Area**

Placing the cursor in the Chart area allows for additional modifications to the chart. The chart can be stretched or compressed. Axes and Chart titles can be clicked and dragged to more appropriate areas.

- **Figure Palette**

Any additional information that the user may want to add to the chart can be done with the Annotations toolbar within the Figure Palette. When the legend is large and redundant, this may be a better alternative. It may also be useful in the build out charts to annotate a production build out with information about the corresponding delivery and dispensing for a given pathway.

- **Hide Plot Tools**

When all edits in the Show Plot tools are done, they can be viewed in the final form by selecting the Hide Plot Tools icon on the toolbar.

Once all necessary adjustments are made the figure can be saved by using the File drop-down menu and selecting Save As. This defaults to your current working directory and a MatLab figure, *.fig, however you can browse the directory to place the file in a separate location and use the drop down list in the 'Save as type' field to find a more suitable format. Please note that resolution will vary from one format to another. If figure is going directly into a document, you may prefer to use Copy Figure from the Edit drop down menu and a Paste Special option at the document to insert the figure with the proper resolution (Paste special, enhanced windows metafile provides good resolution).

9.9.7 Archiving and organizing results

When running multiple results it is easy to lose track of which results correspond to which set of input conditions. It's important to keep input databases together with the results files until all interpretations are completed. Here are a couple of suggestions about how to organize your analyses.

- Create a new folder for each analysis and store results and the input worksheets in that folder when analysis is complete.
- Name folder and database with description of run (i.e. Constant Feedstock Costs).
- Leave Figure numbers (1,2 3, 4 and 9) as part of the figure names.
- Save Figures as *.fig so that adjustments can be made in the future without having to re-run analysis.
- Use the Case Description tab in the input database to record all changes made from previously saved version so that debugging can be made easier.
- Develop an analysis hierarchy so that when a modification is made in one database, its trickled down effect can be quickly determined. See Figure 125 for a sample hierarchy structure.
- Include analysis date in folder or file names. From time to time, an analysis is repeated but results are not, usually because different input sheets were used.

Figure 125. Sensitivity study hierarchy

9.9.8 Running HyPro with MCR

The code for this tool has been converted in the event that MATLAB 7.1 is not available. The alternative means of using this software is through a tool called MATLAB Component Runtime 7.6. This tool has been provided on a CD with the relevant files. However, should

you need to install the software; the information below will walk you through the appropriate steps.

9.9.8.1 Installing the compiler

The properties of the compiler are shown in the figure below.

In order to install the software run the executable entitled MCRInstaller.exe. Then follow repeat the mouse-clicks shown in the next seven figures. You may also be asked what is your preferred location for the software. The figure above indicates one possible folder structure.

Once the software has been installed an additional folder and files should appear in the selected folder.

9.9.8.2 RUN Compiler version of HyPro

Add the HyPro executable files as shown in the figure below to the folder containing MATLAB Component Runtime software. Note that the Hypro.exe file and LOADDATA.xls must be in the same folder. In order to execute the analysis run the executable entitled Hypro.exe. Shortly after starting, a MS-DOS window will appear and slowly begin the loading of the LOADDATA Excel file. The progress of the analysis will be reported in the MS-DOS window as shown in the figure below.

Just as in the MATLAB version of HyPro, you will be prompted to confirm if production plant numbers should be included in the figures. Type 'n' for No.

```
C:\Program Files\MATLAB\MATLAB Component Runtime\Hypro.exe
34 cycles
2033
35 cycles
2034
37 cycles
2035
39 cycles
2036
39 cycles
2037
38 cycles
2038
38 cycles
2039
39 cycles
2040
39 cycles
2041
39 cycles
2042
38 cycles
2043
39 cycles
2044
39 cycles
2045
40 cycles
2046
39 cycles
2047
38 cycles
2048
37 cycles
2049
36 cycles
2050
34 cycles
Elapsed time is 84.765790 seconds.
enable new plant production numbers? (y/n):
```

Similar to the other version of the software, figures will appear for the buildout and cost. Those figures are shown below. Only one of the 4 buildout figures is included here for conciseness, however all 4 will appear. The default plot configurations are slightly different than in the full version of MATLAB, hence the difference between these figures and Figure 121 and Figure 122.

In the figure below we see the toolbar representative of all figures generated by MATLAB Component Runtime. Compared to the toolbar in the full version of MATLAB (see Figure 123), this toolbar offers a reduced number of features. Figures can be saved though and then opened in the full version of MATLAB at a later date for manipulation.

When the analysis is complete the MS-DOS Window will look like the figure below. Note that the last operation performed was writing pathways. If one looks back into the original folder, a new file has been created with the name AllPaths&Years.xls. Just like in the full version of MATLAB, the cost data can be stored in table format. The simulation is now complete. To close out the MS-DOS Window, click on the 'X' in the upper right corner.


```
C:\Program Files\MATLAB\MATLAB Component Runtime\Hypro.exe
38 cycles
2043 cycles
39 cycles
2044 cycles
39 cycles
2045 cycles
40 cycles
2046 cycles
39 cycles
2047 cycles
38 cycles
2048 cycles
37 cycles
2049 cycles
36 cycles
2050 cycles
34 cycles
Elapsed time is 84.793287 seconds.
enable new plant production numbers? (y/n): n
Writing pathway 1 Data
Writing pathway 2 Data
Writing pathway 3 Data
Writing pathway 4 Data
Writing pathway 5 Data
Writing pathway 6 Data
Writing pathway 7 Data
Writing pathway 8 Data
Writing pathway 9 Data
Writing pathway 10 Data
Writing pathway 11 Data
Writing pathway 12 Data
Writing pathway 13 Data
Writing pathway 14 Data
Writing pathway 15 Data
Writing pathway 16 Data
Writing pathway 17 Data
Writing pathway 18 Data
Writing pathway 19 Data
Writing pathway 20 Data
Writing pathway 21 Data
Writing pathway 22 Data
Writing pathway 23 Data
Writing pathway 24 Data
Writing pathway 25 Data
Writing pathway 26 Data
Writing pathway 27 Data
Writing pathway 28 Data
```

9.10 Appendix J – HyPro Input Database

Appendix J

City/Region: CASE DESCRIPTION

-1	File Name	Appendix J - Baseline Database				
	Starter File	19-Jan-2008 (Baseline)				
1/18/2008	Revision Date					
	Modifications					
	Tab Name	Variable	Cell	Current Value	Previous Value	Validation
	CONSTS	H2A Data - Biomass	D16	19.55026015	17.20872952	Constants data was for switchgrass. Changed to Poplar data to match efficiencies used on R, BIO-G and RMM, BIO-G. Changed slope of price increase to match date of usage and CA tipping fee.
	GLOBAL	MSW (1)	Row 26	-\$35/ton(2028) to \$35/ton(2050)	-\$15/ton(2012) to \$25/ton(2030)	Changed tab name to be more representative
	C,MSW (-15to25)-G	Tab Name	N/A	C,MSW (-35to35)-G	C,MSW (-15to25)-G	Changed tab name to be more representative
	C,MSW (+25)-G	Tab Name	N/A	C,MSW (+35)-G	C,MSW (+25)-G	Impact of MSW Option with tipping fees income
	GLOBAL	MSW (2)	Row 26	=\$35/ton/(10.466GJ/ton)	\$2.63/GJ	Added a tab to include the revenue case - same option number so it will override cost case if both are toggled on.
	C,MSW (-35)-G	New Option	N/A	C,MSW (-35)-G	C,MSW (+35)-G	
1/18/2008	Revision Date					
	Modifications					
	Tab Name	Variable	Cell	Current Value	Previous Value	Validation
	All	N/A	N/A	N/A	N/A	Copied each tab individually into new workbook to reduce file size
1/18/2008	Revision Date					
	Modifications					
	Tab Name	Variable	Cell	Current Value	Previous Value	Validation
	All Terminal Sheets	Evap Design Flow Rate	C157	[kgH2/day]	%	Units incorrectly stated
	All Terminal Sheets	Evap Flow Rate	C156	%	[kgH2/day]	Units incorrectly stated
	All Terminal Sheets	Demand/Station [TPD]	Row 36	Demand [TPD]/Initial # of Static	N/A	Added for ease of comparing to static analysis
	CG, EX	Learning Curve	Rows 61-65	N/A		No Learning on existing supply since it won't be built again.
	LA	CO2 Pipeline Distance	Rows 39-40		94	Removed parameters
	All CCS Production tabs	CO2 Pipeline Mileage	H35	=LA/E39		Moved parameter to city page since it will be the same for all options in city
	FC Production Sheets	P&ID Diagram	N	N/A		Reference Distance to city page
					Pasted Image	Removed Images to help reduce file size.
1/17/2008	Revision Date					
	Modifications					
	Tab Name	Variable	Cell	Current Value	Previous Value	Validation
	GLOBAL	GHG Equivalents (Emi)	E54	0 \$	25.00	Carbon tax is removed for the baseline case.
	LA	Demand [TPD]	Row 35	Demand [kg/yr]/365/1000	N/A	Added for ease of comparing to static analysis
	LA	Demand/Station [TPD]	Row 36	Demand [TPD]/Initial # of Static	N/A	Added for ease of comparing to static analysis
1/16/2008	Revision Date					
	Modifications					
	Tab Name	Variable	Cell	Current Value	Previous Value	Validation
	FC,NG-SMR,1.5 (LCLB)	Tab Name	N/A	FC,NG-SMR,1.5 (LCLB)	FC,NG-SMR,1.5	LCLB - Learning Curve Lower Bound
	FC,NG-SMR,1.5 (LCUB)	Tab Name	N/A	FC,NG-SMR,1.5 (LCUB)	FC,NG-SMR,1.5 (UPPER)	LCUP - Learning Curve Upper Bound
	FC,NG-SMR,1.5 (LCLB)	ExternalBuildFixed	H113		2032	Changed CY so that linear build is forecasted in round numbers, 2030 2 units/20 yrs
	FC,NG-SMR,1.5 (LCUB)	ExternalBuildFixed	E112 & F2011 & 2012			Changed to match the ExternalBuildFixed of FC,NG-SMR,1.5 (LCLB)
	FC,NG-SMR,1.5 (LCUB)	ExternalBuildFixed	H112		2032	Changed CY so that linear build is forecasted in round numbers, 2030 2 units/20 yrs
	FC,NG-SMR,1.5 (LCUB)	ExternalBuildFixed	Row 113 0, 3, 5		0,0,0	Changed to match the ExternalBuildFixed of FC,NG-SMR,1.5 (LCLB)
	Production Process Diagrams	N/A	A1	Deleted	Existing	Removed Tab to reduce database size
	CG and C Coals without CCS	Toggle On/Off	A1		-1	Options were made unavailable in order to mimic California's clear air policies.
	C, COAL CCS, 2005					
	R, COAL CCS, 2005					
	C, COAL CCS, 2015					
	R, COAL CCS, 2015					
	C, COAL CCS, 2005					
	R, COAL CCS, 2005					
	C, COAL CCS, 2015					
	R, COAL CCS, 2015					
	C, COAL CCS, 2025					
	R, COAL CCS, 2025					
		CO2 Separation & Sec	E97	0 \$	6,750,000.00	H2A costs for this are covered in other categories on this worksheet.
		Hydrogen Separation	E D21		N/A	Tracking to ensure all equipment in the process is accounted for.
				Added Comment: CO2 separation is addressed with this equipment.		H2A costs for this are covered in other categories on this worksheet.
	C, COAL CCS, 2025, R, COAL CCS, 2025	CO2 Separation & Sec	E96	0 \$	6,750,000.00	Industry discussions suggest that accuracy of information is better so contingency can be reduced. Industry suggested 2% however we have chosen to be conservative
	FC,NG-SMR,0.1					
	FC,NG-SMR,1.5 (LCLB)					
	FC,NG-SMR,1.5 (LCUB)					
	FC,ETH,1.5	Project Contingency	E26	5%	10%	Industry discussions suggest that accuracy of information is better so contingency can be reduced. Industry suggested 2% however we have chosen to be conservative
			L26	55	Varied	
	FC,MMEL-E,0.1					
	FC, MMEL-E,1.5	Project Contingency	E25	5%	10%	Industry discussions suggest that accuracy of information is better so contingency can be reduced. Industry suggested 2% however we have chosen to be conservative
			L25	55	Varied	

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City/Region: CASE DESCRIPTION

	0.1TPD (GT) 1.5TPD (HPGT) 1.5TPD (CryoGT)	Project Contingency	E51 I51	5% 55	10% Varied	Industry discussions suggest that accuracy of information is better so contingency can be reduced. Industry suggested 2% however we have chosen to be conservative Industry discussions suggest that accuracy of information is better so contingency can be reduced. Industry suggested 2% however we have chosen to be conservative Industry discussions suggest that accuracy of information is better so contingency can be reduced. Industry suggested 2% however we have chosen to be conservative
	0.1TPD (LT) 1.5TPD (LT)	Project Contingency	E44 I44	5% 55	10% Varied	
	1.5TPD (PL) 0.1TPD (FC) 1.5TPD (FC)	Project Contingency	E49 I49	5% 55	10% Varied	
1/10/2008	Revision Date					
	Modifications					
	Tab Name	Variable	Cell	Current Value	Previous Value	Validation
	All Terminal, Dispensing & Production Tabs	Process Diagram pictu	N16	Image Removed	Image Included	File size too unwieldy. Condensed all production pictures to a tab to the left of END
	Production Process Diagrams	All	All	H2A diagrams	N/A	Taking into account learning curve expected by 2012 of 180 units built
	FC, NG-SMR, 0.1	Uninstalled Cost	E17	\$ 278,588.91	\$ 350,000.00	Taking into account learning curve expected by 2012 of 3 units built (instead 500)
	FC, NG-SMR, 1.5	Uninstalled Cost	E17	\$ 1,001,671.83	\$ 800,000.00	Taking into account learning curve expected by 2012 of 3 units built (instead 500)
	FC, NG-SMR, 1.5 (UPPER) FC,NG-SMR,0.1, FC, NG-SMR, 1.5 & FC, NG-SMR, 1.5 (UPPER)	Uninstalled Cost	E17	\$ 1,001,671.83	\$ 800,000.00	Taking into account learning curve expected by 2012 of 3 units built (instead 500)
		Learning Factor	H108 - H110		1	Looking for utilization impact on 0.95 cost.
	FC, NG-SMR,0.8 (Co-Prod) 0.8TPD (FC)Co-Prod, C,MSW(-15to25)-G, C,MSW(+25)-G	On/ off toggle	A1		-1	0 Cases not yet vetted.
	Revision Date					
	Modifications					
	Tab Name	Variable	Cell	Current Value	Previous Value	Validation
10/31/2007	All Dispensing tabs	Process Diagram picture	N16	smaller image to reduce file size	larger image = 22 MB database	minimized image file size in hopes of reducing MB of database.
10/31/2007	All COAL tabs, All NG tabs C, COAL-G, 2005 C, COAL-G, 2015 C, COAL-G, 2025	GHG Emissions	Rows 125+ Col M+	varies	based on Sentech work, since value for all cases	Implemented Sentech method on each sheet. Tied Efficiency into Emission Calcs. Tied CCSD & Emissions into Calc Sheet
10/30/2007	C, COAL CCS, 2005	GHG Emissions	Rows 125+ Col M+	varies	based on Sentech work, since value for all cases	Implemented Sentech method on each sheet.
10/19/2007	All Dispensing tabs	Rent	E61, E66, or E68	based on Hook Corrected CCSD Injection equation and made other	based on H2a - Lasher work	Hooks methodology uses a baseline station and NFPA guidelines
10/9/2007	...CCSD Completed FC tabs. Remaining items are carbon emissions and forecourt rent	CCSD	Row 125	labeling corrections		Equation referenced incorrect cell.
10/2/2007	areas	All	Col L			Added Reference List, Source Column, P&ID and verified number with sources.
10/1/2007	complete FC with some questions on FC Co-prod and FC Eth	All	Col L			Added Reference List, Source Column, P&ID and verified number with sources.
10/1/2007	Started Production Cases - complete coal ccs, coal regional, ng smr, ng smr	All	Col L			Added Reference List, Source Column, P&ID and verified number with sources.
9/28/2007	ccs, cg smr, cg coal Started Production Cases - complete bio, nuke, and	All	Col H			Added Reference List, Source Column, P&ID and verified number with sources.
9/26/2007	Coal	All	Col H			Added Reference List, Source Column, P&ID and verified number with sources.
9/26/2007	Finished Terminals	All	Col H			Added Reference List, Source Column, P&ID and verified number with sources.
9/25/2007	Finished Delivery Did GH2 to LT and GH2 to PL	All	Col H			Added Reference List, Source Column, and verified number with sources.
9/24/2007	Finished Dispensing	All	Col H			Added Reference List, Source Column, P&ID and verified number with sources.
9/21/2007	1.5 TPD (FC) 0.1 TPD (FC) R.COAL-G, CCS COAL CCS, 2015	All	Col H			Added Reference List, Source Column, P&ID and verified number with sources.
9/19/2007	NG-SMR, CCS	Many	Rows 12:Many		N/A	Imported CCS Calculations
7/30/2007	Revision Date					
	Modifications					
	Tab Name	Variable	Cell	Current Value	Previous Value	Validation
	GLOBAL	MSW(2)	E83	constant 2.63	increasing from -5.26 to 2.63	constant cost of MSW set to \$25/ton
7/27/2007	Revision Date					
	Modifications					
	Tab Name	Variable	Cell	Current Value	Previous Value	Validation
	GLOBAL	MSW(2)	E26:BR2	increasing from -5.26 to 2.63	constant -1.57	-\$50/ton increasing to \$25/ton
7/25/2007	Revision Date					
	Modifications					
	Tab Name	Variable	Cell	Current Value	Previous Value	Validation
	FC,NG-SMR,0.1	Carbon Emissions	E83	11.775		Added equivalent carbon emissions escaping from stack (which was in 26 April version but somehow did not get into 11 0 May file)

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	FC,NG-SMR,1.5	Carbon Emissions	E83	11.775		Added equivalent carbon emissions escaping from stack (which was in 26 April version but somehow did not get into 11 0 May file)
	FC,NG-SMR,1.5 (UPPER)	Carbon Emissions	E83	11.775		Added equivalent carbon emissions escaping from stack (which was in 26 April version but somehow did not get into 11 0 May file)
	CG,NG-SMR GLOBAL	Carbon Emissions	E56	10.389		Added equivalent carbon emissions escaping from stack (I think the previous 4.02 value erroneously represented a CCS 4.02 value)
7/20/2007		Carbon Emissions	E51	0		0.05 Added high end emissions tax
	Revision Date					
	Modifications					
	Tab Name	Variable	Cell	Current Value	Previous Value	Validation
	C,MSW CONST-G	Tab added				Calls MSW (2) feedstock for constant cost MSW
	C,MSW INCR-G	C,MSW-G, renamed				calls MSW (1) feedstock for variable MSW cost
	ALL PROD & DIST TABS	lines for MSW (1) and MSW (2) added to feedstock efficiency list				
	GLOBAL	lines for MSW (1) and MSW (2) added				
		MSW (1)	E25	-5.26 n/a		increasing cost MSW
			F25	-5.26 n/a		increasing cost MSW
			G25	2.63 n/a		increasing cost MSW
			H25	2.63 n/a		increasing cost MSW
		MSW (2)	E26	-1.57895 n/a		constant cost MSW
			F26	-1.57895 n/a		constant cost MSW
			G26	-1.57895 n/a		constant cost MSW
			H26	-1.57895 n/a		constant cost MSW
7/2/2007	Revision Date					
	Modifications					
	Tab Name	Variable	Cell	Current Value	Previous Value	Validation
	ALL PRODUCTION TABS					Learning curve lines added
	FC,NG-SMR,0.1	Site Prep		changed		
	FC,NG-SMR,1.5	Capital Costs		adjusted for accuracy		
	FC,NG-SMR,1.5 (UPPER)	Permitting		changed		
	FC,MREL-E,0.1	Carbon Emissions		changed		
5/21/2007	Revision Date					
	Modifications					
	Tab Name	Variable	Cell	Current Value	Previous Value	Validation
	R,MSW-G	all	all	varying	none	added tab for R,MSW-G
	GLOBAL	Feedstock cost	Row 25	2.63 n/a		row added for MSW cost
4/23/2007	Revision Date					
	Modifications					
	Tab Name	Variable	Cell	Current Value	Previous Value	Validation
	COAL CCS, 2015	Other	E29	0	1603320	Was double counting CO2 Compressors
	NG-SMR, CCS	CO2 Compressors	E20	0	6623023.923	Was double counting CO2 Compressors
	COAL CCS, 2015	CO2 Pumps	E33	1661108	85911	Error in CO2 Pump formula at the source, D. McCollum.
	NG-SMR, CCS	CO2 Pumps	E28	611267	75413	Error in CO2 Pump formula at the source, D. McCollum.
4/23/2007	Revision Date					
	Modifications					
	Tab Name	Variable	Cell	Current Value	Previous Value	Validation
	R, BIO-G	Oclass	F3			Removed note that was This is for mixed mode delivery (R) incorrect for this sheet.
4/10/2007	Revision Date					
	Modifications					
	Tab Name	Variable	Cell	Current Value	Previous Value	Validation
				$E138*((1000000*(8.5618*(E139/1000)^{0.523})*E138^{LN(E139/1000)^{0.523}})*E138)^{0.9}$		Corrected Learning Curve on multiple liquefier train
	GH2 to LT NEW VERSION	Liquefier Cost	E146, F1 47/LN(2))	0.9 N/A		Add new line for learning factor
	GH2 to LT NEW VERSION	Liquefier Learning Fac	E147			
				$E138*((1000000*(8.5618*(E139/1000)^{0.523})*E138^{LN(E139/1000)^{0.523}})*E138)^{0.9}$		Corrected Learning Curve on multiple liquefier train
	All Terminal Tabs	Liquefier Cost	E146, F1 47/LN(2))	0.9 N/A		Add new line for learning factor
	All Terminal Tabs	Liquefier Learning Fac	E147			Turned on CG SMR plant. Not Coal b/c it doesn't have
	CG, NG-SMR	Activation	A1	0		-1 sequestration
	FC, NG-SMR, 1.5 (UP-CCS) All		All	Deleted Case		Removed b/c it's not feasible to sequester at forecourts
	FC, NG-SMR, 0.8 (Co-Prod) Activation		A1	0		-1 Turned on Production case. Changed start date to match technology
	R, COAL-G+CO2, 2015 (WY CYStart		E4	2015		2020 technology
	RMM, COAL-G+CO2,2015 (CYStart		E4	2015		2020 technology
	0.8TPD (FC) Co-Prod Activation		A1	0		-1 Turned on Dispensing case.
3/16/2007	Revision Date					
	Modifications					
	Tab Name	Variable	Cell	Current Value	Previous Value	Validation
	FC,NG-SMR,1.5	Activation	A1	0		-1 Recreate BSL with CCS options
	PL to 1.5 TPD	CYStart	E4	2025		Allow pipelines to start earlier
	(UPPER) PL to 1.5 TPD	CYStart	E4	2025		2020 b/c of land constraints on FC
						Allow pipelines to start earlier
						2020 b/c of land constraints on FC
1/25/2007	Revision Date					
	Modifications					
	Tab Name	Variable	Cell	Current Value	Previous Value	Validation
	COAL CCS,2015	Many	Red Cell: See Tab			Updated Cost numbers to reflect the 24 kg CO2/kg H2 based on Sentech research
	COAL CCS,2015	Activation	A1	0		-1 Activated tab
	COAL CCS,2015	Emissions	Rows 10: See Tab	Zero		Updated Emissions values based on Sentech research
	NG-SMR, CCS	Many	Red Cell: See Tab			Updated Cost numbers to reflect the 6.8 kg CO2/kg H2 based on Sentech research

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	NG-SMR, CCS	Activation	A1	0	-1	Activated tab
	NG-SMR, CCS	Emissions	Rows 10: See Tab	Zero		Updated Emissions values based on Sentech research
1/25/2007	Revision Date					
	Modifications					
	Tab Name	Variable	Cell	Current Value	Previous Value	Validation
	FC,NG-SMR,1.5	Activation	A1		-1	Remove option to see if pipes 0 come on sooner.
1/25/2007	Revision Date					
	Modifications					
	Tab Name	Variable	Cell	Current Value	Previous Value	Validation
	CG, EX	Activation	A1		0	-1 Forged to include in Baseline earlier
	PL to 1.5 TPD	CYStart	E4		2020	2025 Allow pipelines to start earlier b/c of land constraints on FC
	(UPPER) PL to 1.5 TPD	CYStart	E4		2020	2025 Allow pipelines to start earlier b/c of land constraints on FC
1/24/2007	Revision Date					
	Modifications					
	Tab Name	Variable	Cell	Current Value	Previous Value	Validation
	GH2 to LT NEW VERSION	Liquefier Cost	E146	$(1000000*(8.5618*(E139/1000)^{0.523})*E138)*0.9$	$(1000000*(8.5618*(E139/1000)^{0.523})*E138)$	Included a 0.9 cost scaling factor to multiple train facilities
	LT to 0.1 TPD	Usable Trailer Capacity	E17		95%	Per Brian Bonner of APCI, 95% was more typical of industry
	LT to 1.5 TPD	Usable Trailer Capacity	E17		95%	Per Brian Bonner of APCI, 95% was more typical of industry
	GH2 to PL to CryoGT (WY) NEW VE	Total Pipeline Cost	E41, F41	$=IF(E22=2,0,E40*\$E17/4)$	$=IF(E22=2,0,E40*\$E17)$	Reduced the cost of the pipeline to satisfy the assumption that multiple plants would be built in the area and share the cost of transporting production areas of demand.
1/24/2007	Revision Date					
	Modifications					
	Tab Name	Variable	Cell	Current Value	Previous Value	Validation
	LA	Scenarios	Rows 6 - 5386 TPD Max Demand		7000 TPD Max Demand	Incorrect Max Demand. 7000 represented max # of vehicles (not TPD).
1/23/2007	Revision Date					
	Modifications					
	Tab Name	Variable	Cell	Current Value	Previous Value	Validation
	*CCS Production Methods	Activation	A1		-1	Turned off CCS options to 0 revert to Nov 6 baseline
	GH2 to LT NEW VERSION	Liquefier Cost	E146	$(1000000*(8.5618*(E139/1000)^{0.523})*E138)$	$(1000000*(8.5618*(E139/1000)^{0.523})*E138)*0.9$	Reverted to old Nov 6 Baseline
	LT to 0.1 TPD	Usable Trailer Capacity	E17		90%	95% Reverted to old Nov 6 Baseline
	LT to 1.5 TPD	Usable Trailer Capacity	E17		90%	95% Reverted to old Nov 6 Baseline
	GH2 to PL to CryoGT (WY) NEW VE	Total Pipeline Cost	E41	$=IF(E22=2,0,E40*\$E17)$	$=IF(E22=2,0,E40*\$E17/4)$	Reverted to old Nov 6 Baseline
	FC,NG-SMR,0.8 (Co-Prod) LA	Tab Name	All	FC,NG-SMR,0.8 (Co-Prod)	FC,NG-SMR,0.5(ELEC)	Modified production and dispensing tabs to accommodate co-production option. De-activated in this Excel Sheet. Reverted to old Nov 6 Baseline
		Scenarios	Rows 6 - 7000 TPD Max Demand		4505 TPD Max Demand	
1/16/2007	Revision Date					
	Modifications					
	Tab Name	Variable	Cell	Current Value	Previous Value	Validation
	FC,NG-SMR,1.5 (UP-CCS)	Iclass	E2	[1,5,1,8]	N/A	Inserted new production tab for NG Plant with CO2 Disposal
	NG-SMR,CCS	All CO2 variables	N/A		4.214	Corrected values based on S. M. Benson paper outline sites at 6.5 150 km, and Sentech CO2 rate. Corrected values based on S. M. Benson paper outline sites at 6.5 150 km
	COAL CCS,2015	All CO2 variables	N/A		10.16	6.5 150 km
	LA	Scenarios	Rows 6 - 4505 TPD Max Demand		7000 TPD Max Demand	Incorrect Max Demand. 7000 represented max # of vehicles (not TPD).
1/15/2007	Revision Date					
	Modifications					
	Tab Name	Variable	Cell	Current Value	Previous Value	Validation
	COAL CCS,2015	All CO2 variables	N/A		10.16	Corrected values based on data from Sentech which described mass ratio as 10.16
	LA	Scenarios	Rows 6 - 4505 TPD Max Demand		7000 TPD Max Demand	Incorrect Max Demand. 7000 represented max # of vehicles (not TPD).
1/12/2007	Revision Date					
	Modifications					
	Tab Name	Variable	Cell	Current Value	Previous Value	Validation
	COAL CCS,2015	Iclass	E2	[1,1,1,9]	N/A	Inserted new production tab for Coal Plant with CO2 Disposal
	NG-SMR,CCS	Iclass	E2	[1,3,1,3]	N/A	Inserted new production tab for NG Plant with CO2 Disposal
12/19/2006	Revision Date					
	Modifications					
	Tab Name	Variable	Cell	Current Value	Previous Value	Validation
	C,NG-SMR C,NG-SMR+CO2 CG,NG-SMR FC,NG-SMR,0.1 FC,NG-SMR,1.5 FC,NG-SMR,1.5(UPPER)	Activation	A1		0	-1 Revert to Baseline
	FC,NG-SMR,0.5(ELEC)	All	All	See Tab	N/A	Inserted new production tab to try out the co-production data provided by Air Products
	GH2 to LT NEW VERSION	Liquefier Cost	E146	$(1000000*(8.5618*(E139/1000)^{0.523})*E138)*0.9$	$(1000000*(8.5618*(E139/1000)^{0.523})*E138)$	Included a 0.9 cost scaling factor to multiple train facilities

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	LT to 0.1 TPD	Usable Trailer Capacity	E17	95%	90% was more typical of industry
	LT to 1.5 TPD	Usable Trailer Capacity	E17	95%	90% was more typical of industry
	GH2 to PL to CryoGT (WY) NEW VE	Total Pipeline Cost	E41	=IF(E22=2,0,E40*\$E17/4)	=IF(E22=2,0,E40*\$E17)
					Reduced the cost of the pipeline to satisfy the assumption that multiple plants would be built in the area and share the cost of transporting production areas of demand.
12/6/2006	Revision Date				
	Modifications				
	Tab Name	Variable	Cell	Current Value	Previous Value
	C,NG-SMR				
	C,NG-SMR+CO2				
	CG,NG-SMR				
	FC,NG-SMR,0.1				
	FC,NG-SMR,1.5				
	FC,NG-SMR,1.5(UPPER)	Activation	A1	-1	
					Sensitivity on dependency of 0 foreign NG
11/6/2006	Revision Date				
	Modifications				
	Tab Name	Variable	Cell	Current Value	Previous Value
	All Terminal Tabs	Days of full Plant Production	E149, F1	5	15
					Based on Advisory Board input Outage Storage has been modified to 5 days Changed from 2004 AEO estimate based on input from DOE (M. Paster - \$1.07/gal)
	GLOBAL	Ethanol Feedstock Cost	E16	13.27	14.91
					Adjusted cost to account for pipeline required to bring existing supply to terminal
	CG, EX	Other Variable OM	E44	0.9	0.8
					Baseline should be Scenario 2
	LA	Scenario	E10	2	1
					per S. Gronich
	LA	Min Station Spacing	E19	6.95 10 mi	Baseline should be 40 stations per S. Gronich
	COAL w/o Sequestration	Activation	A1	-1	0
					with sequestration
10/30/2006	Revision Date				
	Modifications				
	Tab Name	Variable	Cell	Current Value	Previous Value
	GH2 to CryoGT NEW VERSION	Design Capacity (kg/yr)	E13	Input	Equation
					Error in cell. Had equation in cell when it should be input from another sheet.
	LA	Scenario	E10	4	1
					Modified to compare storage costs
	1.5 TPD (LT)	Unit Cost, GH2 Storage	F31	\$ 355.00	\$ 300.00
					Correct old assumption of storage cost on non-liquid sheets but forgot to do that on Liquid sheets
	0.1 TPD (LT)	Unit Cost, GH2 Storage	F31	\$ 355.00	\$ 300.00
					Correct old assumption of storage cost on non-liquid sheets but forgot to do that on Liquid sheets
	GH2 to CryoGT NEW VERSION (non-filling) Time/Pick-up	E125, F1 =CryoGT to 1.5TPD	E23		Fixed reference to delivery 1.5 sheet that was lost
	CryoGT to 1.5TPD (filling) Time/Pick-up	E22		2	Cryo cooler Gas will follow 12 Liquid Truck filling assumptions.
	CryoGT to 1.5TPD (non-filling) Time/Pick-up	E23		1	Cryo cooler Gas will follow 1.5 Liquid Truck filling assumptions.
	GH2 to PL to CryoGT (WY) (non-filling) Time/Pick-up	E125, F1 =CryoGT to 1.5TPD	E23		Fixed reference to delivery 1.5 sheet that was lost
	GH2 to PL to CryoGT (RF) (non-filling) Time/Pick-up	E125, F1 =CryoGT to 1.5TPD	E23		Fixed reference to delivery 1.5 sheet that was lost
	GH2 to GT NEW VERSION	Feedstock Efficiency	F216	=1/(E67+E86+E119+E145)*INDEX(FeedstockConv,ROW()-ROW(\$F\$211))	=1/(E67+E86+E119+E145)*INDEX(FeedstockConv,ROW()-ROW(\$E\$211))
					Changed equation reference to proper column
	GH2 to HPGT NEW VERSION	Feedstock Efficiency	F216	=1/(E67+E86+E119+E145)*INDEX(FeedstockConv,ROW()-ROW(\$F\$211))	=1/(E67+E86+E119+E145)*INDEX(FeedstockConv,ROW()-ROW(\$E\$211))
					Changed equation reference to proper column
	GH2 to LT NEW VERSION	Feedstock Efficiency	F216	=1/(F67+F86+F119+8)*INDEX(FeedstockConv,ROW()-ROW(\$G\$215))	=1/(E67+E86+E119+8)*INDEX(FeedstockConv,ROW()-ROW(\$E\$215))
					Changed equation reference to proper column
	GH2 to CryoGT NEW VERSION (Component)	E18		2020	2005
					Adjusted year to match when option becomes available
	GH2 to CryoGT NEW VERSION (Component)	E18		2050	2020
					Adjusted year to match cost points below
	GH2 to PL to CryoGT (RF) N Elec. Power % (relative E65, F65)			40%	50%
					Correct % to mimic Liquefier improvement in 2025
	GH2 to PL to CryoGT (RF) N Peak Energy Req'd (al E66, F66/1000)^-0.1951/3600)			=IF(E57=2,0,E65*(85959*(E60/1000)^-0.1951/3600)*E59)	=IF(E57=2,0,E65*(85959*(E60/1000)^-0.1951/3600)*E59)
					Removed plant qty multiplier used incorrectly in equation
	GH2 to PL to CryoGT (WY) N Elec. Power % (relative E65, F65)			40%	50%
					Correct % to mimic Liquefier improvement in 2025
	GH2 to PL to CryoGT (WY) N Peak Energy Req'd (al E66, F66/1000)^-0.1951/3600)			=IF(E57=2,0,E65*(85959*(E60/1000)^-0.1951/3600)*E59)	=IF(E57=2,0,E65*(85959*(E60/1000)^-0.1951/3600)*E59)
					Removed plant qty multiplier used incorrectly in equation
	GH2 to CryoGT NEW VERSION Elec. Power % (relative E65, F65)			40%	50%
					Correct % to mimic Liquefier improvement in 2025
	GH2 to CryoGT NEW VERSION Peak Energy Req'd (al E66, F66/1000)^-0.1951/3600)			=IF(E57=2,0,E65*(85959*(E60/1000)^-0.1951/3600)*E59)	=IF(E57=2,0,E65*(85959*(E60/1000)^-0.1951/3600)*E59)
					Removed plant qty multiplier used incorrectly in equation
10/27/2006	Revision Date				
	Modifications				
	Tab Name	Variable	Cell	Current Value	Previous Value
	PL to 1.5 TPD	Calendar Year, Deprec	E40	2050	2020
					no changes occur so midpoint is removed
	PL to 1.5 TPD	Many	Col G	N/A	equal to Col F
					Removed column b/c no changes occur between CY Begin and CY End
	PL to 1.5 TPD	Activation	A1	-1	0
					Baseline case is with \$1M/mi 0 urban pipeline

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	LA	Scenario	E10		1	Baseline Case: Use this 4 penetration curve	
10/25/2006	Revision Date						
	Modifications						
	Tab Name	Variable	Cell	Current Value	Previous Value	Validation	
	GH2 to GT NEW VERSION	Pressures in 2050	F82, 83,	Same as column E	Old values	Modified to be consistent with 2005 values.	
10/24/2006	Revision Date						
	Modifications						
	Tab Name	Variable	Cell	Current Value	Previous Value	Validation	
	R, COAL-G+CO2, 2015 (WY Sheet Name		N/A	R, COAL-G+CO2, 2015 (WY)	C, COAL-G+CO2, 2015 (WY)	Modified nomenclature to reflect regional location of option	
	RMM, COAL-G+CO2, 2015 (Oclass		E3	[2.2.-3] N/A		New production option created for Wyoming coal to pair with trucking and full piping deliveries	
	FC, NG-SMR,1.5 (UPPER)	Feedstock Efficiency	E3 G52, H52	0.75		0.8 Capped efficiency at 75%	
	FC, NG-SMR,1.5 (UPPER)	Depreciable Capital	E31	\$ 2,557,652.06	\$ 2,186,027.40	Adjusted Capital Cost of Production so that its sum with Dispensing was equal to \$4.4 M or 10% more than lower bound	
10/17/2006	Revision Date						
	Modifications						
	Tab Name	Variable	Cell	Current Value	Previous Value	Validation	
	GH2 to GT	Storage, GH2	\$21:\$29		0 75,986 m2	Removed Gaseous Storage & Replaced with Liquid Storage as cheaper alternative	
	GH2 to GT	Storage, LH2	\$22:\$27	1,711 m2	N/A	Removed Gaseous Storage & Replaced with Liquid Storage as cheaper alternative	
	GH2 to GT	Storage Compressors	\$30:\$40		0 2,407 kW [ea]	Removed Storage Compressors & Replaced with 10% Scale Liquefier & Evaporator as cheaper alternative	
	GH2 to GT	Liquefier	\$28:\$34	15.91 kWh/kgH2	N/A	Removed Storage Compressors & Replaced with 10% Scale Liquefier & Evaporator as cheaper alternative	
	GH2 to GT	Evaporator	\$36:\$39	15.91 kWh/kgH2	N/A	Removed Storage Compressors & Replaced with 10% Scale Liquefier & Evaporator as cheaper alternative	
	GH2 to GT	Unit Cost, Storage	\$67	N/A	\$818/kgH2	Removed Gaseous Storage Costs & Replaced with Liquid Storage Costs (Depreciable Capital Costs)	
	GH2 to GT	Storage	\$67	=1000000*(0.0321*(E25/1000) +0.8174)	N/A	Removed Gaseous Storage Unit Costs & Replaced with Liquid StorageTotal Costs (Depreciable Capital Costs)	
	GH2 to GT	Storage	\$68	N/A	=1.1*E67*(E28)	Removed Gaseous Storage Total Costs & Replaced with Liquefier Total Costs (Depreciable Capital Costs)	
	GH2 to GT	Liquefiers	\$68	=1000000*(8.5618*(E32/1000) ^0.523)*E31	N/A	Removed Gaseous Storage Total Costs & Replaced with Liquefier Total Costs (Depreciable Capital Costs)	
	GH2 to GT	Storage Compressors	\$70	N/A	=E32*E\$69*40094*(E39^0.667 4)	Removed Costs. Compressors	
	GH2 to GT	Compressor Cost Fact	\$69	Moved to \$70		N/A	
	GH2 to GT	Evaporator	\$69	=E37*8.65866666666667	N/A	Moved to make room for Evaporator Costs	
	GH2 to GT	Feedstock Efficiency	E112	=E37*8.65866666666667	N/A	Approximated Evaporator Costs @ \$8.6586/kgH2 evaporated	
	GH2 to GT	Installed Costs		=SUM(E67:E69)+E71+E73+E77	=E67+E71+E73+E75+E76+E77	Modified Electricity Efficiency to include Liquefier and exclude Storage Compressors	
	GH2 to GT	Yearly Power Req'd	E35	=(E\$34*(1*E\$29*(E\$25/E\$1N/A		Included the Liquefier and Evaporator Costs in Total Cost Equation	
10/16/2006	Revision Date						
	Modifications						
	Tab Name	Variable	Cell	Current Value	Previous Value	Validation	
	GH2 to GT	Storage	E68, F68=1.1*E67*(E28)		=1.1*E67*(E28)^0.8	Scaling Factor not applicable in large volumes	
	GH2 to HPGT	Storage	E68, F68=1.1*E67*(E28)		=1.1*E67*(E28)^0.8	Scaling Factor not applicable in large volumes	
	GH2 to CryoGT	Storage	E76	=1.1*E75*(E28)	=1.1*E75*(E28)^0.8	Scaling Factor not applicable in large volumes	
	GH2 to PL to CryoGT (RF)	Storage	E110	=1.1*E109*(E48)	=1.1*E109*(E48)^0.8	Scaling Factor not applicable in large volumes	
	GH2 to PL to CryoGT (WY)	Storage	E110	=1.1*E109*(E48)	=1.1*E109*(E48)^0.8	Scaling Factor not applicable in large volumes	
	GH2 to GT	Days	E27		15	Changed days of storage to 3 upper bound of 15.	
	GH2 to HPGT	Days	E27		15	Changed days of storage to 3 upper bound of 15.	
	GH2 to CryoGT	Days	E27		15	Changed days of storage to 3 upper bound of 15.	
	GH2 to LT	Days	E20		15	Changed days of storage to 3 upper bound of 15.	
	GH2 to PL to CryoGT (RF)	Days	E47		15	Changed days of storage to 3 upper bound of 15.	
	GH2 to PL to CryoGT (WY)	Days	E47		15	Changed days of storage to 3 upper bound of 15.	
	C,BIO-G	All	All	None	C,BIO-G	Removed production option	

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	R,BIO-G	Iclass	E2	[1,7,1,1]	[1,7,1,2]	Renumbered Biomass option
	RMM,BIO-G	Iclass	E2	[1,7,1,2]	[1,7,1,3]	Renumbered Biomass option
	GH2 to GT	Unit Cost, Storage	F67		355	300 per reference quote
	GH2 to HPGT	Unit Cost, Storage	F67		355	300 per reference quote
	GH2 to CryoGT	Unit Cost, Storage	E75		355	300 per reference quote
	GH2 to PL to CryoGT (RF)	Unit Cost, Storage	E109		355	300 per reference quote
	GH2 to PL to CryoGT (WY)	Unit Cost, Storage	E109		355	300 per reference quote
Not Done	GH2 to GT	Unit Cost, Storage	G67		320 N/A	per reference quote
Not Done	GH2 to HPGT	Unit Cost, Storage	G67		320 N/A	per reference quote
Not Done	GH2 to CryoGT	Unit Cost, Storage	F75		320 N/A	per reference quote
Not Done	GH2 to PL to CryoGT (RF)	Unit Cost, Storage	F109		320 N/A	per reference quote
Not Done	GH2 to PL to CryoGT (WY)	Unit Cost, Storage	F109		320 N/A	per reference quote
	CryoGT to 1.5TPD	Unit Cost, Trailer	E35		\$745,000	\$500,000 based on \$/kg of HP Storage
	0.1TPD (GT)	Unit Cost, Storage	F42		355	300 per reference quote
	1.5TPD (HPGT)	Unit Cost, Storage	F42		355	300 per reference quote
	1.5TPD (CryoGT)	Unit Cost, Storage	E42		355	300 per reference quote
	1.5TPD (PL)	Unit Cost, Storage	F41		355	300 per reference quote
	1.5TPD (FC)	Unit Cost, Storage	F41		355	300 per reference quote
	1.5TPD (FC)	Unit Cost, Storage	F41		355	300 per reference quote
Not Done	0.1TPD (GT)	Unit Cost, Storage	G42		320 N/A	per reference quote
Not Done	1.5TPD (HPGT)	Unit Cost, Storage	G42		320 N/A	per reference quote
Not Done	1.5TPD (CryoGT)	Unit Cost, Storage	F42		320 N/A	per reference quote
Not Done	1.5TPD (PL)	Unit Cost, Storage	G41		320 N/A	per reference quote
Not Done	1.5TPD (FC)	Unit Cost, Storage	G41		320 N/A	per reference quote
Not Done	1.5TPD (FC)	Unit Cost, Storage	G41		320 N/A	per reference quote
						used 26.12 GJ/metric ton &
	GLOBAL	Electric Utility Steam CE13	\$	1.22	2.339671044	\$31.9/metric ton
						used 26.12 GJ/metric ton &
	GLOBAL	Electric Utility Steam CE24	\$	0.78	1.169835522	\$20.5/metric ton

10/10/2006	Revision Date					
	Modifications					
Tab Name	Variable	Cell	Current Value	Previous Value	Validation	
1.5TPD (CryoGT)	DepreciableCapital (Di D45	CryoGT Trailer		HPGT Trailer	Correcting mislabeling of trailer type.	
1.5TPD (CryoGT)	DepreciableCapital (Di E45	\$	500,000.00	\$	1,000,000.00	Changed assumption from 2 trailers to 1 trailer at dispensing station
GH2 to CryoGT	Trailer Capacity	E43		2100	1100	Based on APCI Comments
CryoGT to 1.5TPD	Trailer Capacity	E20		2100	1100	CryoGT capacity was modified
1.5 TPD (CryoGT)	Maximum Pressure	E20	(136 atm) =CryoGT to 1.5TPD!E17	(476 atm) =HPGT to 1.5TPD!E17	1100	CryoGT capacity was modified
CryoGT to 1.5TPD	Maximum Pressure	E20		136	476	Incorrect sheet reference. Based on APCI Comments
GH2 to CryoGT	Maximum Pressure	E22, E42		136 425, 476		CryoGT pressure was modified from 7000 psi to 2000 psi
GH2 to CryoGT	Liquefiers	GH2 to LT; Liquefier Rows 65- Equations		N/A		Based on APCI Comments, a liquefier has been added to the CryoGT Terminal
GH2 to CryoGT	DepreciableCapital (Di E86	1/2*(Liquefier for LT Delivery) =E76+E78+E79+E81+E83+E8		N/A		Based on APCI Comments, a liquefier has been added to the CryoGT Terminal
GH2 to CryoGT	DepreciableCapital (Di E87	4+E85+E86		4+E85		Cost of Liquefier included in Installed Cost equation
GH2 to PL to CryoGT (WY)	Liquefiers	GH2 to LT; Liquefier Rows 85- Equations		N/A		Based on APCI Comments, a liquefier has been added to the CryoGT Terminal
GH2 to PL to CryoGT (WY)	DepreciableCapital (Di E120	1/2*(Liquefier for LT Delivery) =E110+E112+E113+E115+E1		N/A		Based on APCI Comments, a liquefier has been added to the CryoGT Terminal
GH2 to PL to CryoGT (WY)	DepreciableCapital (Di E121	17+E118+E119+E120		17+E118+E119		Cost of Liquefier included in Installed Cost equation
GH2 to PL to CryoGT (WY)	Maximum Pressure, St E42			136	425	Based on APCI Comments
GH2 to PL to CryoGT (RF)	Liquefiers	GH2 to LT; Liquefier Rows 85- Equations		N/A		CryoGT power consumption is 6 kWh/kg.
GH2 to PL to CryoGT (RF)	DepreciableCapital (Di E120	1/2*(Liquefier for LT Delivery) =E110+E112+E113+E115+E1		N/A		Based on APCI Comments
GH2 to PL to CryoGT (RF)	DepreciableCapital (Di E121	17+E118+E119+E120		17+E118+E119		CryoGT power consumption is 6 kWh/kg.
GH2 to PL to CryoGT (RF)	Maximum Pressure, St E42			136	425	Based on APCI Comments
GH2 to CryoGT	Feedstock Efficiency	E121	5.623708889	32.6573=1/(24*(E40/E35+E54/		CryoGT power consumption is 6 kWh/kg.
GH2 to PL to CryoGT (WY)	Feedstock Efficiency	E156	5.623708889	21.0423=1/(24*(E60/E55+E74/		CryoGT power consumption is 6 kWh/kg.
GH2 to PL to CryoGT (RF)	Feedstock Efficiency	E156	5.623708889	21.0423=1/(24*(E60/E55+E74/		CryoGT power consumption is 6 kWh/kg.

10/9/2006	Revision Date					
	Modifications					
Tab Name	Variable	Cell	Current Value	Previous Value	Validation	
GLOBAL	FeedstockCosts	C13, D13	2.339671044	1.169835522	Double Cost of Coal Feedstock. Relabeled as Central. Used in all Central Coal Production Cases.	
GLOBAL	FeedstockCosts	C24, D24	1.169835522	N/A	Created a new Feedstock called Coal (Regional). Set value to EIA value previously used in all coal cases.	
CONSTS	FeedstockConv	C25, D25	4.6505	N/A	Created a new Feedstock Conversion called Coal (Regional). Set value to EIA value previously used in all coal cases.	
C.COAL-G+CO2,2015 (WY)	FeedstockEfficiency	D66, E66	0	0.6091	Removed Central Coal from this Case.	

Appendix J

City/Region: CASE DESCRIPTION

10/6/2006	C,COAL-G+CO2,2015 (WY)	FeedstockEfficiency	C77, D77	0.6091	N/A	Added Regional Coal to this case. Added Regional Coal to this array on all sheets for matrix multiplication
	All Sheets	FeedstockEfficiency	Last Row	0	N/A	
10/6/2006	Revision Date					
	Modifications					
10/6/2006	Tab Name	Variable	Cell	Current Value	Previous Value	Validation
	OMM,BIO-G	Iclass	E2	1,7,1,3	1,7,1,2	Have to change the Iclass otherwise it will overwrite other production case with this one
	R,BIO-G	None	Tab Nam R,BIO-G		O,BIO-G	Clarified that Biomass Plant is Regional, R
	RMM,BIO-G	None	Tab Nam RMM,BIO-G		OMM,BIO-G	Clarified that Biomass Plant is Regional, R
	(UPPER) PL to 1.5TPD	None	Tab Nam (UPPER) PL to 1.5TPD		PL -> 1.5TPD (UPPER)	Clarified cost on this tab are the upper limit of pipeline not dispensing
	All Terminals & Deliveries	None	Tab Nam to		->	Clarified labeling of methods for easier reading
	CCGT	None	Tab Nam CryoGT		CCGT	Renamed delivery method per numerous requests
	GH2 to LT	Days	E20 F92, F97, G86-		3	Changed days of storage to 3 to match days of storage at terminals for gaseous truck deliveries. Selected 3 as lower bound quantity.
	GH2 to LT	Feedstock Efficiency	G124 G92, G97, G86, G89, G109, G112, G115, G122, H86-	3.374225333	4.820321905	Liquefier in the near future (2015) will consume same power (10 kWh/kg) per APCI. (Calculation in cells to left)
	GH2 to LT	Feedstock Efficiency	H124	4.217781667	4.820321905	Liquefier in the later future (2025) will consume 1/5 less power (10 kWh/kg --> 8 kWh/kg) per APCI. Additional column added for symmetry from row 86 to end. (Calculation in cells to left)
10/5/2006	Revision Date					
	Modifications					
10/5/2006	Tab Name	Variable	Cell	Current Value	Previous Value	Validation
	GT->0.1TPD	Dist to CG	E13	=INDEX(LAIE17:K17,1,LOOKUP(E12,LAIE16:K16))	=INDEX(LAIE17:G17,1,LOOKUP(E12,LAIE16:G16))	Extended the lookup array so the O, BIO-G production case would be evaluated at Location 5, 346 mi. from city
	HPGT->1.5TPD	Dist to CG	E13	=INDEX(LAIE17:K17,1,LOOKUP(E12,LAIE16:K16))	=INDEX(LAIE17:G17,1,LOOKUP(E12,LAIE16:G16))	Extended the lookup array so the O, BIO-G production case would be evaluated at Location 5, 346 mi. from city
	CCGT->1.5TPD	Dist to CG	E13	=INDEX(LAIE17:K17,1,LOOKUP(E12,LAIE16:K16))	=INDEX(LAIE17:G17,1,LOOKUP(E12,LAIE16:G16))	Extended the lookup array so the O, BIO-G production case would be evaluated at Location 5, 346 mi. from city
	LT->0.1TPD	Dist to CG	E13	=INDEX(LAIE17:K17,1,LOOKUP(E12,LAIE16:K16))	=INDEX(LAIE17:G17,1,LOOKUP(E12,LAIE16:G16))	Extended the lookup array so the O, BIO-G production case would be evaluated at Location 5, 346 mi. from city
	LT->1.5TPD	Dist to CG	E13	=INDEX(LAIE17:K17,1,LOOKUP(E12,LAIE16:K16))	=INDEX(LAIE17:G17,1,LOOKUP(E12,LAIE16:G16))	Extended the lookup array so the O, BIO-G production case would be evaluated at Location 5, 346 mi. from city
	GH2->PL	Distance	E17	=INDEX(LAIE17:K17,1,LOOKUP(E12,LAIE16:K16))	=INDEX(LAIE17:G17,1,LOOKUP(E12,LAIE16:G16))	Extended the lookup array so the O, BIO-G production case would be evaluated at Location 5, 346 mi. from city
	OMM,BIO-G	Oclass	E3	2,3,-3	N/A	Added new production case to match rice fields in Modesto, CA with Mixed Mode Delivery (PL to CCGT)
	GH2->PL->CCGT (RF)	Iclass	E2	2,3,-3,1	N/A	Added new delivery case to match rice fields in Modesto, CA with Mixed Mode Delivery (PL to CCGT)
10/3/2006	Revision Date					
	Modifications					
10/3/2006	Tab Name	Variable	Cell	Current Value	Previous Value	Validation
	GT->0.1TPD	Unit Cost, Trailer	E35	\$ 225,000.00	\$ 165,000.00	Update H2A price with estimate from APCI
	LT->1.5TPD	Unit Cost, Tractor	E33	\$ 75,000.00	\$ 100,000.00	Update H2A price with estimate from APCI
	LT->0.1TPD	Unit Cost, Tractor	E33	\$ 75,000.00	\$ 100,000.00	Update H2A price with estimate from APCI
	CCGT->1.5TPD	Unit Cost, Tractor	E34	\$ 75,000.00	\$ 100,000.00	Update H2A price with estimate from APCI
	HPGT->1.5TPD	Unit Cost, Tractor	E34	\$ 75,000.00	\$ 100,000.00	Update H2A price with estimate from APCI
	GT->0.1TPD	Unit Cost, Tractor	E34	\$ 75,000.00	\$ 100,000.00	Update H2A price with estimate from APCI
	LT->1.5TPD	Labor Cost	E64	\$ 40.00	\$ 30.00	Update H2A price with estimate from APCI
	LT->0.1TPD	Labor Cost	E64	\$ 40.00	\$ 30.00	Update H2A price with estimate from APCI
	CCGT->1.5TPD	Labor Cost	E64	\$ 40.00	\$ 30.00	Update H2A price with estimate from APCI
	HPGT->1.5TPD	Labor Cost	E64	\$ 40.00	\$ 30.00	Update H2A price with estimate from APCI
	GT->0.1TPD	Labor Cost	E64	\$ 40.00	\$ 30.00	Update H2A price with estimate from APCI
	Global	Feedstock Costs	E15	2.563953488	2.367703497	Per S. Gronich, increase biomass price to \$40/ton (Calculation in cells to left)
	0.1TPD (GT)	GT Trailer	E45	Added Comment	N/A	Comment: Each Dispensing Station has 2 trailers to: a) cut down on # of deliveries req'd in a day, and b) allow for a more flexible delivery schedule rather than a 'just in time' approach.

	1.5TPD (HPGT)	GT Trailer	E45	Added Comment	N/A	Comment: Each Dispensing Station has 2 trailers to; a) cut down on # of deliveries req'd in a day, and b) allow for a more flexible delivery schedule rather than a 'just in time' approach.
	1.5TPD (CCGT)	GT Trailer	E45	Added Comment	N/A	Comment: Each Dispensing Station has 2 trailers to; a) cut down on # of deliveries req'd in a day, and b) allow for a more flexible delivery schedule rather than a 'just in time' approach.
	GH2->LT	Feedstock Efficiency	F92, F97, G86-G124	4.820321905	3.374225333	Liquefier in the future (2015) will consume 1/3 less power (10 kWh/kg --> 7 kWh/kg) per APCI. Additional column added for symmetry from row 86 to end. (Calculation in cells to left)
	GT->0.1TPD	Trips	E26	Added Comment	N/A	Comment: 24/2 is 12 hrs which is the number of hrs truck is able to deliver due to transportation/ road permit limitations.
	HPGT->1.5TPD	Trips	E26	Added Comment	N/A	Comment: 24/2 is 12 hrs which is the number of hrs truck is able to deliver due to transportation/ road permit limitations.
	CCGT->1.5TPD	Trips	E26	Added Comment	N/A	Comment: 24/2 is 12 hrs which is the number of hrs truck is able to deliver due to transportation/ road permit limitations.
	LT->0.1TPD	Trips	E26	Added Comment	N/A	Comment: 24/2 is 12 hrs which is the number of hrs truck is able to deliver due to transportation/ road permit limitations.
	LT->1.5TPD	Trips	E26	Added Comment	N/A	Comment: 24/2 is 12 hrs which is the number of hrs truck is able to deliver due to transportation/ road permit limitations.
	LA	Scenarios	Row 9	Scenario 4	N/A	Added Constant Demand of 100% as Scenario Option
10/2/2006	Revision Date					
	Modifications					
	Tab Name	Variable	Cell	Current Value	Previous Value	Validation
	All	--	A1	0	-1	Turned all production, delivery and dispensing cases on
	Global	Feedstock Costs	E15	2.367703497	1.20921637	Per S. Gronich, increase biomass price to \$42/ton
	LA	Distance	I13 - I16	346	N/A	Add 5th location other to consider the effects of moving single production type
	O, BIO-G	ALL	ALL	See Tab	N/A	Added new production case to place plant at rice fields in Modesto, CA

-1	Variable	[Units]	(y-axis, x-axis)	Data	
	Physical Constants				
	Rho_LH2	[g/L]		70.80581242	
	R_GH2	[J mol-1 K-1]		8.3144	
	K_GH2 (Cp/Cv)			1.41	
	LHV_H2	[GJ/kg]		0.121472112	0.033742253
	GJ_PER_KWh			0.0036	
	FeedstockConv				
			(Feedstock)		H2A Data
	[(GJ.H2/GJFS)/(kgH2.Nm^FS)]		Commercial Natural Gas	3.3171	36.61952684
	[(GJ.H2/GJFS)/(kgH2.Nm^FS)]		Industrial Natural Gas	3.3171	36.61952684
	[(GJ.H2/GJFS)/(kgH2.Nm^FS)]		Electric Utility Natural Gas	3.3171	36.61952684
	[(GJ.H2/GJ)/(kgH2.kWh)]		Commercial Electricity	33.7423	3.6
	[(GJ.H2/GJ)/(kgH2.kWh)]		Industrial Electricity	33.7423	3.6
	[(GJ.H2/GJFS)/(kgH2.kgFS)]		c Utility Steam Coal (Central	4.6505	26.12043145
	[(GJ.H2/GJFS)/(kgH2.L)]		Diesel Fuel	3.3928	35.80310436
	[(GJ.H2/GJFS)/(kgH2.kgFS)]		Biomass	6.2133	19.55026015
	[(GJ.H2/GJFS)/(kgH2.L)]		Ethanol	5.7095	21.27560106
	[(GJ.H2/GJFS)/(kgH2.L)]		Methanol	7.6123	15.95739762
	[(GJ.H2/GJFS)/(kgH2.L)]		Gasoline	3.7540	32.35797886
	[(GJ.H2/GJFS)/(kgH2.kgFS)]		Steam	#VALUE!	??
	[(GJ.H2/L)/(kgH2.L)]		Cooling Water	0.1215	1000
	[(GJ.H2/L)/(kgH2.L)]		Demineralized Water	0.1215	1000
	[(GJ.H2/L)/(kgH2.L)]		Process Water	0.1215	1000
	[(GJ.H2.Barel)]		Bio-oli	0.1215	1000
	[(GJ.H2/GJFS)/(kgH2.kgFS)]		Utility Steam Coal (Regional	4.6505	26.12043145
	ByproductConv				
			(Byproduct)		
	[(GJ.H2/GJ)/(kgH2.kWh)]		Commercial Electricity	-33.7423	-3.6
	[(GJ.H2/GJFS)/(kgH2.kgFS)]		Steam	#VALUE!	??
	Engineering Approximations				
	DefaultRR			10%	
	PlantTemperature	[deg. C]		25	
	PlantPressure	[atm]		20	
	PipelineRho_GH2	[Rho_Air]		0.06897	

Appendix J

City/Region: GLOBAL

Variable	[Units]	(y-axis,x-axis)		Data
VarData	CYStart	[Year]		2005
VarData	CYStop	[Year]		2050
Axis	CY			[2005:2050]
VarData	CYBegin			2012
VarData	CYEnd			2050
VarLinear	FeedstockCosts		(Feedstock,CY)	
Data				

julie_perez:
Changed from 2004 AEO estimate based on
input from DOE (M. Paster - \$1.07/gal)

2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
\$6.05611	\$6.16950	\$6.35217	\$6.45082	\$6.46485	\$6.49058	\$6.53951	\$6.61607	\$6.67778	\$6.73950	\$6.80121	\$6.86293	\$6.92464	\$6.98636	\$7.04807	\$7.10979	\$7.17150	\$7.23322	\$7.33438	\$7.43554	\$7.53669
\$4.03363	\$4.14850	\$4.34274	\$4.42396	\$4.42467	\$4.44071	\$4.48502	\$4.56936	\$4.63769	\$4.70602	\$4.77435	\$4.84268	\$4.91101	\$4.97934	\$5.04767	\$5.11600	\$5.18433	\$5.25266	\$5.32612	\$5.39958	\$5.47304
\$4.01807	\$4.13626	\$4.32108	\$4.39809	\$4.39611	\$4.40659	\$4.45740	\$4.53988	\$4.60472	\$4.66955	\$4.73439	\$4.79923	\$4.86407	\$4.92891	\$4.99374	\$5.05858	\$5.12342	\$5.18826	\$5.26082	\$5.33338	\$5.40594
\$32.22180	\$32.59169	\$33.08551	\$33.42609	\$33.40338	\$33.30405	\$33.43112	\$33.61925	\$33.82002	\$34.02079	\$34.22156	\$34.42233	\$34.62309	\$34.82386	\$35.02463	\$35.22540	\$35.42617	\$35.62693	\$35.61293	\$35.59892	\$35.58492
\$22.27032	\$22.62203	\$23.09202	\$23.34564	\$23.32495	\$23.27847	\$23.38733	\$23.55644	\$23.75083	\$23.94523	\$24.13963	\$24.33403	\$24.52842	\$24.72282	\$24.91722	\$25.11162	\$25.30601	\$25.50041	\$25.49039	\$25.48036	\$25.47034
\$0.97305	\$0.97621	\$0.99568	\$1.00263	\$1.01178	\$1.01548	\$1.02725	\$1.03685	\$1.04407	\$1.05129	\$1.05850	\$1.06572	\$1.07293	\$1.08015	\$1.08736	\$1.09458	\$1.10179	\$1.10901	\$1.11226	\$1.11551	\$1.11876
\$12.58026	\$12.59291	\$12.62953	\$12.70973	\$12.72999	\$12.78489	\$12.92018	\$13.33124	\$13.35978	\$13.38833	\$13.41688	\$13.44542	\$13.47397	\$13.50251	\$13.53106	\$13.55961	\$13.58815	\$13.61670	\$13.76082	\$13.90494	\$14.04907
\$2.74220	\$2.79402	\$2.83340	\$2.94948	\$2.98886	\$3.00129	\$3.05311	\$3.08213	\$3.27878	\$3.47543	\$3.67208	\$3.86873	\$4.06538	\$4.26202	\$4.45867	\$4.65532	\$4.85197	\$5.04862	\$5.19287	\$5.33711	\$5.48136
\$13.27000	\$13.27000	\$13.27000	\$13.27000	\$13.27000	\$13.27000	\$13.27000	\$13.27000	\$13.27000	\$13.27000	\$13.27000	\$13.27000	\$13.27000	\$13.27000	\$13.27000	\$13.27000	\$13.27000	\$13.27000	\$13.27000	\$13.27000	\$13.27000
\$9.14940	\$9.14940	\$9.14940	\$9.14940	\$9.14940	\$9.14940	\$9.14940	\$9.14940	\$9.14940	\$9.14940	\$9.14940	\$9.14940	\$9.14940	\$9.14940	\$9.14940	\$9.14940	\$9.14940	\$9.14940	\$9.14940	\$9.14940	\$9.14940
\$14.72710	\$14.79053	\$14.72882	\$14.98959	\$15.15746	\$15.30288	\$15.44581	\$15.54852	\$15.63699	\$15.72537	\$15.81379	\$15.90222	\$15.99064	\$16.07906	\$16.16749	\$16.25591	\$16.34434	\$16.43276	\$16.60669	\$16.78062	\$16.95455
\$4.78000	\$4.78000	\$4.78000	\$4.78000	\$4.78000	\$4.78000	\$4.78000	\$4.78000	\$4.78000	\$4.78000	\$4.78000	\$4.78000	\$4.78000	\$4.78000	\$4.78000	\$4.78000	\$4.78000	\$4.78000	\$4.78000	\$4.78000	\$4.78000
\$0.00002	\$0.00002	\$0.00002	\$0.00002	\$0.00002	\$0.00002	\$0.00002	\$0.00002	\$0.00002	\$0.00002	\$0.00002	\$0.00002	\$0.00002	\$0.00002	\$0.00002	\$0.00002	\$0.00002	\$0.00002	\$0.00002	\$0.00002	\$0.00002
\$0.00132	\$0.00132	\$0.00132	\$0.00132	\$0.00132	\$0.00132	\$0.00132	\$0.00132	\$0.00132	\$0.00132	\$0.00132	\$0.00132	\$0.00132	\$0.00132	\$0.00132	\$0.00132	\$0.00132	\$0.00132	\$0.00132	\$0.00132	\$0.00132
\$0.00044	\$0.00044	\$0.00044	\$0.00044	\$0.00044	\$0.00044	\$0.00044	\$0.00044	\$0.00044	\$0.00044	\$0.00044	\$0.00044	\$0.00044	\$0.00044	\$0.00044	\$0.00044	\$0.00044	\$0.00044	\$0.00044	\$0.00044	\$0.00044
\$0.00000	\$0.00000	\$0.00000	\$0.00000	\$0.00000	\$0.00000	\$0.00000	\$0.00000	\$0.00000	\$0.00000	\$0.00000	\$0.00000	\$0.00000	\$0.00000	\$0.00000	\$0.00000	\$0.00000	\$0.00000	\$0.00000	\$0.00000	\$0.00000
\$0.70759	\$0.71074	\$0.73022	\$0.73716	\$0.74632	\$0.75001	\$0.76178	\$0.77139	\$0.77880	\$0.78582	\$0.79303	\$0.80025	\$0.80746	\$0.81468	\$0.82190	\$0.82911	\$0.83633	\$0.84354	\$0.84679	\$0.85005	\$0.85330
-\$3.34416	-\$3.34416	-\$3.34416	-\$3.34416	-\$3.34416	-\$3.34416	-\$3.34416	-\$3.34416	-\$3.34416	-\$3.34416	-\$3.34416	-\$3.34416	-\$3.34416	-\$3.34416	-\$3.34416	-\$3.34416	-\$3.34416	-\$3.34416	-\$3.34416	-\$3.34416	-\$3.34416
-\$3.34416	-\$3.34416	-\$3.34416	-\$3.34416	-\$3.34416	-\$3.34416	-\$3.34416	-\$3.34416	-\$3.34416	-\$3.34416	-\$3.34416	-\$3.34416	-\$3.34416	-\$3.34416	-\$3.34416	-\$3.34416	-\$3.34416	-\$3.34416	-\$3.34416	-\$3.34416	-\$3.34416

2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051	2052	2053	2054	2055	2056	2057	2058	2059
\$7.63785	\$7.73901	\$7.84017	\$7.94133	\$8.04249	\$8.14365	\$8.24481	\$8.34597	\$8.44713	\$8.54829	\$8.64945	\$8.75061	\$8.85177	\$8.95293	\$9.05409	\$9.15525	\$9.25641	\$9.35757	\$9.45873	\$9.55989	\$9.66105
\$5.54650	\$5.61996	\$5.69342	\$5.76688	\$5.84034	\$5.91380	\$5.98726	\$6.06072	\$6.13418	\$6.20764	\$6.28110	\$6.35456	\$6.42802	\$6.50148	\$6.57494	\$6.64840	\$6.72186	\$6.79532	\$6.86878	\$6.94224	\$7.01570
\$5.47850	\$5.55106	\$5.62362	\$5.69618	\$5.76874	\$5.84130	\$5.91386	\$5.98642	\$6.05898	\$6.13154	\$6.20410	\$6.27666	\$6.34922	\$6.42178	\$6.49434	\$6.56690	\$6.63946	\$6.71202	\$6.78458	\$6.85714	\$6.92970
\$35.57091	\$35.55690	\$35.54290	\$35.52889	\$35.51489	\$35.50088	\$35.48688	\$35.47287	\$35.45887	\$35.44486	\$35.43085	\$35.41685	\$35.40285	\$35.38884	\$35.37484	\$35.36084	\$35.34684	\$35.33284	\$35.31884	\$35.30484	\$35.29084
\$25.46031	\$25.45029	\$25.44026	\$25.43024	\$25.42021	\$25.41019	\$25.40016	\$25.39014	\$25.38011	\$25.37009	\$25.36006	\$25.35004	\$25.34001	\$25.33000	\$25.32000	\$25.31000	\$25.30000	\$25.29000	\$25.28000	\$25.27000	\$25.26000
\$1.12202	\$1.12527	\$1.12852	\$1.13177	\$1.13502	\$1.13827	\$1.14152	\$1.14478	\$1.14803	\$1.15128	\$1.15453	\$1.15778	\$1.15998	\$1.16217	\$1.16437	\$1.16656	\$1.16876	\$1.17096	\$1.17315	\$1.17535	\$1.17754
\$14.19319	\$14.33731	\$14.48144	\$14.62556	\$14.76968	\$14.91381	\$15.05793	\$15.20206	\$15.34618	\$15.49030	\$15.63443	\$15.77855	\$15.86839	\$15.95823	\$16.04808	\$16.13792	\$16.22776	\$16.31761	\$16.40745	\$16.49729	\$16.58713
\$5.62561	\$5.76985	\$5.91410	\$6.05835	\$6.20259	\$6.34684	\$6.49109	\$6.63533	\$6.77958	\$6.92382	\$7.06807	\$7.21232	\$7.35656	\$7.50081	\$7.64506	\$7.78930	\$7.93355	\$8.07780	\$8.22204	\$8.36629	\$8.51053
\$13.27000	\$13.27000	\$13.27000	\$13.27000	\$13.27000	\$13.27000	\$13.27000	\$13.27000	\$13.27000	\$13.27000	\$13.27000	\$13.27000	\$13.27000	\$13.27000	\$13.27000	\$13.27000	\$13.27000	\$13.27000	\$13.27000	\$13.27000	\$13.27000
\$9.14940	\$9.14940	\$9.14940	\$9.14940	\$9.14940	\$9.14940	\$9.14940	\$9.14940	\$9.14940	\$9.14940	\$9.14940	\$9.14940	\$9.14940	\$9.14940	\$9.14940	\$9.14940	\$9.14940	\$9.14940	\$9.14940	\$9.14940	\$9.14940
\$17.12848	\$17.30241	\$17.47634	\$17.65027	\$17.82420	\$17.99813	\$18.17206	\$18.34599	\$18.51992	\$18.69384	\$18.86777	\$19.04170	\$19.15013	\$19.25855	\$19.36697	\$19.47540	\$19.58382	\$19.69224	\$19.80067	\$19.90909	\$20.01751
\$4.78000	\$4.78000	\$4.78000	\$4.78000	\$4.78000	\$4.78000	\$4.78000	\$4.78000	\$4.78000	\$4.78000	\$4.78000	\$4.78000	\$4.78000	\$4.78000	\$4.78000	\$4.78000	\$4.78000	\$4.78000	\$4.78000	\$4.78000	\$4.78000
\$0.00002	\$0.00002	\$0.00002	\$0.00002	\$0.00002	\$0.00002	\$0.00002	\$0.00002	\$0.00002	\$0.00002	\$0.00002	\$0.00002	\$0.00002	\$0.00002	\$0.00002	\$0.00002	\$0.00002	\$0.00002	\$0.00002	\$0.00002	\$0.00002
\$0.00132	\$0.00132	\$0.00132	\$0.00132	\$0.00132	\$0.00132	\$0.00132	\$0.00132	\$0.00132	\$0.00132	\$0.00132	\$0.00132	\$0.00132	\$0.00132	\$0.00132	\$0.00132	\$0.00132	\$0.00132	\$0.00132	\$0.00132	\$0.00132
\$0.00044	\$0.00044	\$0.00044	\$0.00044	\$0.00044	\$0.00044	\$0.00044	\$0.00044	\$0.00044	\$0.00044	\$0.00044	\$0.00044	\$0.00044	\$0.00044	\$0.00044	\$0.00044	\$0.00044	\$0.00044	\$0.00044	\$0.00044	\$0.00044
\$0.00000	\$0.00000	\$0.00000	\$0.00000	\$0.00000	\$0.00000	\$0.00000	\$0.00000	\$0.00000	\$0.00000	\$0.00000	\$0.00000	\$0.00000	\$0.00000	\$0.00000	\$0.00000	\$0.00000	\$0.00000	\$0.00000	\$0.00000	\$0.00000
\$0.85655	\$0.85980	\$0.86305	\$0.86630	\$0.86955	\$0.87281	\$0.87606	\$0.87931	\$0.88256	\$0.88581	\$0.88906	\$0.89231	\$0.89451	\$0.89671	\$0.89890	\$0.90110	\$0.90329	\$0.90549	\$0.90768	\$0.90988	\$0.91208
-\$0.08991	\$0.21403	\$0.51796	\$0.82190	\$1.12584	\$1.42977	\$1.73371	\$2.03765	\$2.34158	\$2.64552	\$2.94946	\$3.34416	\$3.34416	\$3.34416	\$3.34416	\$3.34416	\$3.34416	\$3.34416	\$3.34416	\$3.34416	\$3.34416
\$3.34416	\$3.34416	\$3.34416	\$3.34416	\$3.34416	\$3.34416	\$3.34416	\$3.34416	\$3.34416	\$3.34416	\$3.34416	\$3.34416	\$3.34416	\$3.34416	\$3.34416	\$3.34416	\$3.34416	\$3.34416	\$3.34416	\$3.34416	\$3.34416

2060	2061	2062	2063	2064	2065	2066	2067	2068	2069	2070
\$8.91657	\$8.93316	\$8.94976	\$8.96636	\$8.98295	\$8.99955	\$9.01662	\$9.03368	\$9.05075	\$9.06782	\$9.08489
\$6.47508	\$6.48713	\$6.49918	\$6.51124	\$6.52329	\$6.53534	\$6.54773	\$6.56013	\$6.57252	\$6.58492	\$6.59731
\$6.39570	\$6.40760	\$6.41951	\$6.43141	\$6.44331	\$6.45522	\$6.46746	\$6.47970	\$6.49195	\$6.50419	\$6.51643
\$35.64183	\$35.66433	\$35.68683	\$35.70933	\$35.73183	\$35.75432	\$35.77704	\$35.79975	\$35.82246	\$35.84518	\$35.86789
\$25.51108	\$25.52718	\$25.54328	\$25.55939	\$25.57549	\$25.59159	\$25.60785	\$25.62411	\$25.64036	\$25.65662	\$25.67288
\$1.17974	\$1.18194	\$1.18413	\$1.18633	\$1.18852	\$1.19072	\$1.19298	\$1.19524	\$1.19749	\$1.19975	\$1.20201
\$16.67698	\$16.76682	\$16.85666	\$16.94650	\$17.03635	\$17.12619	\$17.22371	\$17.32122	\$17.41874	\$17.51625	\$17.61377
\$8.65478	\$8.79903	\$8.94327	\$9.08752	\$9.23177	\$9.37601	\$9.52026	\$9.66450	\$9.80875	\$9.95300	\$10.09724
\$13.27000	\$13.27000	\$13.27000	\$13.27000	\$13.27000	\$13.27000	\$13.27000	\$13.27000	\$13.27000	\$13.27000	\$13.27000
\$9.14940	\$9.14940	\$9.14940	\$9.14940	\$9.14940	\$9.14940	\$9.14940	\$9.14940	\$9.14940	\$9.14940	\$9.14940
\$20.12593	\$20.23436	\$20.34278	\$20.45120	\$20.55963	\$20.66805	\$20.78573	\$20.90342	\$21.02110	\$21.13878	\$21.25647
\$4.78000	\$4.78000	\$4.78000	\$4.78000	\$4.78000	\$4.78000	\$4.78000	\$4.78000	\$4.78000	\$4.78000	\$4.78000
\$0.00002	\$0.00002	\$0.00002	\$0.00002	\$0.00002	\$0.00002	\$0.00002	\$0.00002	\$0.00002	\$0.00002	\$0.00002
\$0.00132	\$0.00132	\$0.00132	\$0.00132	\$0.00132	\$0.00132	\$0.00132	\$0.00132	\$0.00132	\$0.00132	\$0.00132
\$0.00044	\$0.00044	\$0.00044	\$0.00044	\$0.00044	\$0.00044	\$0.00044	\$0.00044	\$0.00044	\$0.00044	\$0.00044
\$0.00000	\$0.00000	\$0.00000	\$0.00000	\$0.00000	\$0.00000	\$0.00000	\$0.00000	\$0.00000	\$0.00000	\$0.00000
\$0.91427	\$0.91647	\$0.91866	\$0.92086	\$0.92306	\$0.92525	\$0.92751	\$0.92977	\$0.93203	\$0.93428	\$0.93654
\$3.34416	\$3.34416	\$3.34416	\$3.34416	\$3.34416	\$3.34416	\$3.34416	\$3.34416	\$3.34416	\$3.34416	\$3.34416
\$3.34416	\$3.34416	\$3.34416	\$3.34416	\$3.34416	\$3.34416	\$3.34416	\$3.34416	\$3.34416	\$3.34416	\$3.34416

Appendix J

1	Variable	[Units]
	TaxRate (State)	[%]
	TaxRate (Federal)	[%]
VarData	TaxRate	[%]
Var	Scenarios	[kg/yr]
	1	6.5%
	2	15.0%
	3	15.3%
	4	100.0%
	Scenario	
Var	Demand	[kgH2/year]
Data	RegionSize	[mi2]
VarData	LandCosts	[\$/acre]
Var	Distance	[mi]
Data	Distance, CG=>Station	[mi]
VarData	MinStationSpacing	[mi]
	Demand	[TPD]
	Demand / Station	
	CO2 Pipeline Distance	[mi]
	CO2 Pipeline Distance	[km]

LA demand was incorrectly set at max 7000 tpd. Correct Max Demand is 5386 tpd. All curves appropriately scaled down (JP - 1/24/07).
Reference: Vehicle Distribution for HyTRANS 2, Vehicle Distribution Progress Sheet. Fuel Consumption and Mileage Assumptions are from H2A. Extrapolation done with MinON2.m file.

City/Region: LA

(y-axis, x-axis)

Data	6%
	35%
	38.90%

WARNING

Depending on the scenario you select you may also need to change CYBegin on the GLOBAL tab
Scenario 1: CYBegin=2015; Scenario 2/3: CYBegin=2012

(CY)	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
by 2025	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	1.08E+06	2.15E+06	3.66E+06
by 2025	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	2.15E+05	6.45E+05	1.08E+06	9.68E+06	2.26E+07	3.98E+07
by 2024	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	2.15E+05	6.45E+05	1.08E+06	6.45E+06	1.51E+07	2.58E+07
in 1st yr	1.97E+09	1.97E+09	1.97E+09	1.97E+09	1.97E+09	1.97E+09	1.97E+09	1.97E+09	1.97E+09	1.97E+09	1.97E+09	1.97E+09	1.97E+09

(CY)

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	2.15E+05	6.45E+05	1.08E+06	9.68E+06	2.26E+07	3.98E+07

(Location)

	1	2	3	4	5
\$50,000.00	\$400,000.00	\$0.00	\$5,000.00	\$5,000.00	
1668	Central	City Gate	Forecourt	Other	

(Location)

	1	2	3	4	5
\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	
60	0	0	1000	346	
34.034					
6.95					
6.457553716					
7.071067812					

Wyoming

0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	5.89E-01	1.77E+00	2.95E+00	2.65E+01	6.19E+01	1.09E+02
								0.015	0.044	0.074	0.663		

2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
7.96E+06	1.66E+07	2.84E+07	4.35E+07	6.17E+07	8.11E+07	1.03E+08	1.28E+08	1.63E+08	2.06E+08	2.59E+08	3.23E+08	4.00E+08	4.88E+08	5.89E+08	7.01E+08	8.22E+08	9.48E+08	1.08E+09	1.20E+09	1.32E+09
6.13E+07	8.71E+07	1.15E+08	1.45E+08	1.77E+08	2.12E+08	2.53E+08	2.97E+08	3.61E+08	4.34E+08	5.18E+08	6.11E+08	7.13E+08	8.22E+08	9.35E+08	1.05E+09	1.16E+09	1.27E+09	1.37E+09	1.46E+09	1.55E+09
4.41E+07	6.99E+07	1.04E+08	1.45E+08	1.90E+08	2.44E+08	3.02E+08	3.63E+08	4.32E+08	5.11E+08	5.98E+08	6.93E+08	7.95E+08	9.00E+08	1.01E+09	1.12E+09	1.22E+09	1.32E+09	1.41E+09	1.49E+09	1.57E+09
1.97E+09	1.97E+09	1.97E+09	1.97E+09	1.97E+09	1.97E+09	1.97E+09	1.97E+09	1.97E+09	1.97E+09	1.97E+09	1.97E+09	1.97E+09	1.97E+09	1.97E+09	1.97E+09	1.97E+09	1.97E+09	1.97E+09	1.97E+09	1.97E+09
2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
6.13E+07	8.71E+07	1.15E+08	1.45E+08	1.77E+08	2.12E+08	2.53E+08	2.97E+08	3.61E+08	4.34E+08	5.18E+08	6.11E+08	7.13E+08	8.22E+08	9.35E+08	1.05E+09	1.16E+09	1.27E+09	1.37E+09	1.46E+09	1.55E+09

1.68E+02	2.39E+02	3.15E+02	3.98E+02	4.86E+02	5.81E+02	6.93E+02	8.13E+02	9.88E+02	1.19E+03	1.42E+03	1.67E+03	1.95E+03	2.25E+03	2.56E+03	2.88E+03	3.18E+03	3.48E+03	3.76E+03	4.01E+03	4.24E+03

2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051	2052	2053	2054	2055	2056	2057	2058	2059
1.42E+09	1.52E+09	1.60E+09	1.67E+09	1.73E+09	1.78E+09	1.82E+09	1.85E+09	1.88E+09	1.90E+09	1.91E+09	1.93E+09	1.95E+09	1.95E+09	1.95E+09	1.95E+09	1.95E+09	1.95E+09	1.95E+09	1.95E+09	1.95E+09
1.62E+09	1.68E+09	1.73E+09	1.78E+09	1.81E+09	1.84E+09	1.87E+09	1.89E+09	1.91E+09	1.92E+09	1.93E+09	1.94E+09	1.95E+09	1.95E+09	1.95E+09	1.95E+09	1.95E+09	1.95E+09	1.95E+09	1.95E+09	1.95E+09
1.63E+09	1.69E+09	1.74E+09	1.78E+09	1.81E+09	1.84E+09	1.87E+09	1.89E+09	1.90E+09	1.92E+09	1.93E+09	1.93E+09	1.95E+09	1.95E+09	1.95E+09	1.95E+09	1.95E+09	1.95E+09	1.95E+09	1.95E+09	1.95E+09
1.97E+09	1.97E+09	1.97E+09	1.97E+09	1.97E+09	1.97E+09	1.97E+09	1.97E+09	1.97E+09	1.97E+09	1.97E+09	1.97E+09	1.97E+09	1.97E+09	1.97E+09	1.97E+09	1.97E+09	1.97E+09	1.97E+09	1.97E+09	1.97E+09
2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051	2052	2053	2054	2055	2056	2057	2058	2059
1.62E+09	1.68E+09	1.73E+09	1.78E+09	1.81E+09	1.84E+09	1.87E+09	1.89E+09	1.91E+09	1.92E+09	1.93E+09	1.94E+09	1.95E+09	1.95E+09	1.95E+09	1.95E+09	1.95E+09	1.95E+09	1.95E+09	1.95E+09	1.95E+09

4.43E+03	4.60E+03	4.75E+03	4.87E+03	4.97E+03	5.05E+03	5.12E+03	5.18E+03	5.22E+03	5.26E+03	5.28E+03	5.31E+03	5.33E+03	5.33E+03	5.33E+03	5.33E+03	5.33E+03	5.33E+03	5.33E+03	5.33E+03	5.33E+03

2060	2061	2062	2063	2064	2065	2066	2067	2068	2069	2070
1.95E+09	1.95E+09	1.95E+09	1.95E+09	1.95E+09	1.95E+09	1.95E+09	1.95E+09	1.95E+09	1.95E+09	1.95E+09
1.95E+09	1.95E+09	1.95E+09	1.95E+09	1.95E+09	1.95E+09	1.95E+09	1.95E+09	1.95E+09	1.95E+09	1.95E+09
1.95E+09	1.95E+09	1.95E+09	1.95E+09	1.95E+09	1.95E+09	1.95E+09	1.95E+09	1.95E+09	1.95E+09	1.95E+09
1.97E+09	1.97E+09	1.97E+09	1.97E+09	1.97E+09	1.97E+09	1.97E+09	1.97E+09	1.97E+09	1.97E+09	1.97E+09
2060	2061	2062	2063	2064	2065	2066	2067	2068	2069	2070
1.95E+09	1.95E+09	1.95E+09	1.95E+09	1.95E+09	1.95E+09	1.95E+09	1.95E+09	1.95E+09	1.95E+09	1.95E+09

5.33E+03	5.33E+03	5.33E+03	5.33E+03	5.33E+03	5.33E+03	5.33E+03	5.33E+03	5.33E+03	5.33E+03	5.33E+03

Production: C,COAL-G,2005

Variable	[Units]	(y-axis, x-axis)	Data	Source Used
VarData	IClass		[1,1,1,1]	
VarData	OClass		[2,1,-1]	
VarData	CYStart	[Year]	2005	
VarData	CYStop	[Year]	2050	
Axis	CY		[2005,2050]	
VarData	IRR	[%]	10%	
VarData	DepreciationLength	[Years]	20	
VarData	AnalysisPeriod	[Years]	20	
VarData	Life	[Years]	40	
Axis	PY		[1,40]	
VarData	DesignCapacity	[kgH2/day]	283.830	
VarData	DesignCapacity	[kgH2/year]	103,597,950	
VarData	CapacityFactor	[% of DesignCapacity]	90%	
VarData	Location			
DepreciableCapital (Direct)				
		(Component)	Uninstalled Costs Installation Factor Installed Costs	
		Coal Handling Prep & Feed	\$20,030,413.64 152% \$31,041,178.28	
		Feedwater & Misc. BOP Systems	\$3,615,840.00 147% \$5,316,840.00	
		Gasifier & Accessories	\$61,000,733.91 138% \$84,244,436.65	
		Air Separation Unit	\$58,523,040.00 100% \$58,523,040.00	
		Hydrogen Separation & Gas Cleanup	\$55,393,280.00 100% \$55,393,280.00	
		HRSG Ducting & Stack	\$15,896,800.00 118% \$18,776,950.00	
		Steam Turbine Generator	\$12,938,160.00 122% \$15,767,910.00	
		Cooling Water System	\$4,297,940.00 148% \$6,369,490.00	
		Ash Handling System	\$5,690,360.00 141% \$8,016,110.00	
		Accessory Electric Plant	\$7,800,840.00 157% \$12,273,840.00	
		I&C	\$6,955,160.00 153% \$10,666,910.00	
		Buildings & Structures	\$3,073,418.88 194% \$5,972,927.09	
		Zinc Oxide Polisher	\$310,000.00 185% \$572,500.00	
		Uninstalled Costs	\$255,525,886.44	
		Installed Costs	\$312,935,410.02	
DepreciableCapital (Indirect)				
		(Component)		
		Site Preparation	2%	
		Engineering & Design	10%	
		Process Contingency	\$0.00	
		Project Contingency	15%	
		Other Depreciable Capital	\$0.00	
		One-Time Licensing Fees	\$0.00	
		Up-Front Permitting Costs	15%	
		[% of Uninstalled Costs]		
VarLinear	DepreciableCapital	[(CY)]	2005 2050	
Data			\$434,608,663.22 \$434,608,663.22	
VarData	LandRequired	[acres]	250	
FixedOM				
		(Component)		
		FTEs	100	
		Labor Costs	\$50.00	
		Labor Costs	\$10,400,000.00	
		Overhead & Misc.	20%	
		Property Tax & Insurance	2%	
		Rent	\$0.00	
		Lic., Permits and Fees	\$0.00	
		Mat'l for Maint. & Repairs	0.6%	
		Other Fees	\$0.00	
		Other Fixed O&M Costs	\$0.00	
VarLinear	FixedOM	[(PY,CY)]	2005 2050	
Data			\$23,049,785.72 \$23,049,785.72	
End			\$23,049,785.72 \$23,049,785.72	
VarLinear	OtherFixed	[(PY,CY)]	2005 2050	
Data			\$0.00 \$0.00	
End			\$0.00 \$0.00	
VarLinear	FeedstockEfficiency	(Feedstock,CY)	2005 2050	
Data			0.0000 0.0000	
		Commercial Natural Gas	0.0000 0.0000	
		Industrial Natural Gas	0.0000 0.0000	
		Electric Utility Natural Gas	0.0000 0.0000	
		Commercial Electricity	0.0000 0.0000	
		Industrial Electricity	0.0000 0.0000	
		Utility Steam Coal (Central)	0.5466 0.5466	
		Diesel Fuel	0.0000 0.0000	
		Biomass	0.0000 0.0000	
		Ethanol	0.0000 0.0000	
		Methanol	0.0000 0.0000	
		Gasoline	0.0000 0.0000	
		Steam	0.0000 0.0000	
		Cooling Water	0.0000 0.0000	
		Demineralized Water	0.0000 0.0000	
		Process Water	0.0108 0.0108	
		Bio-oil	0.0000 0.0000	
		lity Steam Coal (Regional)	0.0000 0.0000	
		MSW (1)	0.0000 0.0000	
		MSW (2)	0.0000 0.0000	
End				
OtherVariableOM				
		(Component)		
		WT Costs	\$101,000.00	
		S&WD Costs	\$994,000.00	
		Other Variable Op. Costs	\$2,417,000.00	
		Royalties	\$0.00	
		Operator Profit	\$0.00	
		Subsidies, Tax Incentives	\$0.00	
		CO2 Separation & Seq.	\$0.00	
VarLinear	OtherVariableOM	[(PY,CY)]	2005 2050	
Data			\$0.0366 \$0.0366	
End			\$0.0366 \$0.0366	
VarLinear	ByproductEfficiency	(Byproduct,CY)	2005 2050	
Data			10.627% 10.627%	
		Byproduct Electricity	0.0000 0.0000	
		Steam	0.0000 0.0000	
VarLinear	Emissions	(Species,CY)	2005 2050	
Data			0 0	
		Carbon	0 0	
		GHG Equivalents	22.60 22.60383793	
		NOx	0 0	
		SOx	0 0	
		Particulates (PM10)	0 0	
		Mercury	0 0	
End				
ReplacementCosts				
		(PY,CY)	2005 2050	
Data			\$2,173,043.32 \$2,173,043.32	
End			\$2,173,043.32 \$2,173,043.32	
VarLinear	LearningFactor	(Technology,Factor)	IClass[1] (L) ICClass[2] (L) ICClass[4] (L) Factor	
Data		FC.NG-SMR,1.5 (UPPER)	1 5 3 1	
End		FC.NG-SMR,1.5	1 5 2 1	
VarData	InitialUnitNo	[unit # in CYBegin]	500	
VarData	LearningFactorStart		1	
Plant Description				
To arrive at a cost estimate for hydrogen, the design included commercially available process technology obtained from verifiable sources. The plant utilized commercially available technology including a Wabash River-scale Conoco-Phillips (EGas) gasifier, conventional gas cooling, commercial shift conversion and end gas cleanup, commercial sulfuric acid technology, and commercial pressure swing adsorption (PSA). The EGas gasifier is the gasifier of choice for this study since it has been operated on both bituminous and sub-bituminous coals.				
H2A has this as a % of DepreciableCapital+LandCosts. We do not multiply by Land Costs because Land Costs are computer in MATLAB.				
Each row corresponds to a technology sheet. Building one of the current sheet will decrease the cost of every technology listed by the corresponding "Factor." The numbers in the first three columns are the 1st, 2nd and 4th numbers of the technology to-be-chosen's IClass var				
All delivery (1-3) sheets with the same J share a LearningFactor (e.g., LT to 0.1TPD and LT to 1.5TPD only need one LearningFactor, since both sheets represent the same underlying technology - LTs). The L for this common factor should always be 1, and the factor should appear on every sheet that shares it.				
Building an upper-bound FC ought to decrease the cost of a normal FC by the same amount. You would probably want a similar LearningFactor (maybe even a reference) on the normal FC sheet				

Variable	[Units]	Data		Source Used		
VarData ICClass		[1,1,1,2] [2,1,-1]				
VarData OClass		2015				
VarData CYStart	[Year]	2050				
VarData CYStop	[Year]	[2015-2050]				
Axis C	CY	10%				
VarData DepreciationLength	[Years]	20				
VarData AnalysisPeriod	[Years]	20				
VarData Life	[Years]	40				
Axis PY	PY	[1-40]				
DesignCapacity	[kgH2/day]	316,289				
DesignCapacity	[kgH2/day]	115,445,485				
CapacityFactor	[% of DesignCapacity]	90%				
Location		-1				
DepreciableCapital (Direct)	(Component)	Uninstalled Costs Coal Handling Prep & Fees \$20,030,413.64 Feedwater & Misc. BOP Systems \$2,643,325.71 Gasifier & Accessories \$61,000,733.91 Air Separation Unit \$34,786,960.00 Hydrogen Separation & Gas Cleanup \$48,851,040.00 HRSG Ducting & Stack \$0.00 Steam Turbine Generator \$9,462,427.63 Cooling Water System \$4,297,840.00 Ash Handling System \$5,690,360.00 Accessory Electric Plant \$3,715,213.82 I&C \$6,955,160.00 Buildings & Structures \$3,073,418.88 Other \$0.00 Uninstalled Costs \$200,506,893.60 Installed Costs \$251,213,380.47	Installation Factor 155% 147% 138% 100% 100% 118% 122% 148% 141% 157% 153% 194% 100% 15% 2050	Installed Costs \$31,041,176.29 \$3,886,825.71 \$84,244,436.65 \$34,786,960.00 \$48,851,040.00 \$0.00 \$11,531,988.10 \$6,309,490.00 \$8,016,110.00 \$5,845,516.63 \$10,666,910.00 \$5,972,927.09 \$0.00 \$371,620,180.40 \$371,620,180.40	Plant Description Hot raw gas from the E-Gas gasifier is cooled and sent to the SCODS process for desulfurization. Elemental sulfur is produced as a byproduct. The clean gas is filtered goes through a hydrogen separation membrane where the surface shift reaction occurs and hydrogen is separated from CO2. A portion of the hydrogens is fired to heat compressed air entering the ITM oxygen separation unit. Pure oxygen produced from the ITM is cooled and compressed for use in the gasifier. The remaining hydrogen is compressed for product delivery. The CO2-rich stream is fired with oxygen and expanded to recover energy as power.	20
DepreciableCapital (Indirect)	(Component)	Site Preparation 1.2% Engineering & Design 10% Process Contingency \$0.00 Project Contingency 25% Other Depreciable Capital \$0.00 One-Time Licensing Fees \$0.00 Up-Front Permitting Costs 15% Total Indirect Costs \$371,620,180.40			20	
VarLinear LandRequired	[acres]	250			20	
FixedOM	(Component)	FTEs 100 Labor Costs \$50.00 Labor Costs \$10,400,000.00 Overhead and G&A 20% Property Tax & Insurance 2% Rent \$0.00 Lic., Permits and Fees \$0.00 Mat'l for Maint. & Repairs 0.6% Other Fees \$0.00 Other Fixed O&M Costs \$0.00 Total Fixed OM Costs \$10,400,000.00			20	
VarLinear OtherFixed	[\$/year]	\$21,419,683.89			20	
End		\$21,419,683.89			20	
VarLinear FeedstockEfficiency	(Feedstock,CY)	2015 2050			20	
Data	(GJ,H2/GJFeedstock)	Commercial Natural Gas 0.0000 0.0000 Industrial Natural Gas 0.0000 0.0000 Electric Utility Natural Gas 0.0000 0.0000 Commercial Electricity 0.0000 0.0000 Industrial Electricity 0.0000 0.0000 Jillit Steam Coal (Central) 0.6091 0.6091 Diesel Fuel 0.0000 0.0000 Biomass 0.0000 0.0000 Ethanol 0.0000 0.0000 Methanol 0.0000 0.0000 Gasoline 0.0000 0.0000 Steam 0.0000 0.0000 Cooling Water 0.0000 0.0000 Demineralized Water 0.0000 0.0000 Process Water 0.0101 0.0101 Bio-oil 0.0000 0.0000 Jillit Steam Coal (Regional) 0.0000 0.0000 MSW (1) 0.0000 0.0000 MSW (2) 0.0000 0.0000			20	
End					20	
OtherVariableOM	(Component)	WT Costs \$100,000.00 SWD Costs \$796,000.00 Other Variable Op. Costs \$1,029,000.00 Royalties \$0.00 Operator Profit \$0.00 Subsidies, Tax Incentives \$0.00 CO2 Separation & Seq. \$0.00			20	
VarLinear OtherVariableOM	[\$/kgH2]	2015 2050			20	
Data		\$0.0185 \$0.0185			20	
ByproductEfficiency	(Byproduct,CY)	2015 2050			20	
Data	(GJ,H2/GJ)	Byproduct Electricity -168,711.33 -168,711.33 Steam 0.0000 0.0000			20	
Emissions	(Species,CY)	2015 2050			20	
Data		Carbon 0 0 GHG Equivalents 20,284,473.75 20,284,473.75 NOx 0 0 SOx 0 0 Particulates (PM10) 0 0 Mercury 0 0			20	
ReplacementCosts	(\$)	(PY,CY) 2015 2050 \$1,858,100.90 \$1,858,100.90 \$1,858,100.90 \$1,858,100.90			20	
LearningFactor	(Technology,Factor)	IClass[1] (I) IClass[2] (J) IClass[4] (L) Factor			20	
InitialUnitNo	[unit # in CYBegin]	FC,NG-SMR,1.5 (UPPER) 1 5 3 1 FC,NG-SMR,1.5 500 1			20	
LearningFactorStart		1			20	

Site Prep & Permitting Costs are % of Uninstalled Costs. This deviates from Reference 20 & 21. We believe Reference is in error.

H2A has this as a % of Depreciable Capital + LandCosts. We do not multiply by Land Costs because Land Costs are computed in MATLAB.

40gpm @ \$2500/yr-gpm

79600 tonne/yr @ \$10/tonne

Shift catalyst: Amine- & PSA, SO2 Catalyst Consumables.

0.5% of Depreciable-Capital

Each row corresponds to a technology sheet. Building one of the current sheet will decrease the cost of every technology listed by the corresponding "Factor". The numbers in the first three columns are the 1st, 2nd and 4th numbers of the technology to be "changed" in Class var.

All delivery (1-3) sheets with the same J share a LearningFactor (e.g., LT to 0 LTPD and LT to 1 LTDP only need one LearningFactor, since both sheets represent the same underlying technology - LTs). The L for this common factor should always be 1, and the factor should appear on every sheet that shares it.

Building an upper-bound FC ought to decrease the cost of a normal FC by the same amount. You would probably want a similar LearningFactor (maybe even a reference) on the normal FC sheet

Production: C,COAL-G,2025

C.COAL-G.2025

Variable	[Units]	(y-axis,x-axis)	Data	Source Used
VarData	IClass		[1,1,1,4]	
VarData	OClass		[2,1,-1]	
VarData	CYStart	[Year]	2005	22
VarData	CYStop	[Year]	2050	
Axis	CY	CY	[2005-2050]	
VarData	IRR	[%]	10%	22
VarData	DepreciationLength	[Years]	20	22
VarData	AnalysisPeriod	[Years]	20	
VarData	Life	[Years]	40	22
Axis	PY	PY	[1-40]	
VarData	DesignCapacity	[kgH2/day]	307.673	22
VarData	DesignCapacity	[kgH2/year]	112,300,645	
VarData	CapacityFactor	[% of DesignCapacity]	90%	22
VarData	Location		1	
Plant Description To arrive at a cost estimate for hydrogen, the design included commercially available process technology obtained from verifiable sources. The plant utilized commercially available technology including a Wabash River-scale Destec (EGS) gasifier, conventional gas cooling, commercial shift conversion and acid gas cleanup, commercial sulfuric acid technology, and commercial pressure swing adsorption (PSA). Two-stage Selexol is used to remove CO2. CO2 is compressed to 2200 psi for sequestration. The EGS gasifier is the gasifier of choice for this study since it has been operated on both bituminous and sub-bituminous coals.				
DepreciableCapital (Direct)				
	(Component)	Uninstalled Costs	Installation Factor	Installed Costs
	Coal Handling Prep & Feed	\$20,030,413.64	155%	\$31,041,176.28
	Feedwater & Misc. BOP Systems	\$3,615,840.00	147%	\$5,316,840.00
	Gasifier & Accessories	\$51,415,039.00	138%	\$71,006,211.20
	Air Separation Unit	\$77,509,920.00	100%	\$77,509,920.00
	Hydrogen Separation & Gas Cleanup	\$106,312,640.00	100%	\$106,312,640.00
	HRSO Ducting & Stack	\$15,896,800.00	118%	\$18,776,950.00
	Steam Turbine Generator	\$11,137,717.00	122%	\$13,573,695.85
	Cooling Water System	\$3,751,819.00	148%	\$5,560,275.30
	Ash Handling System	\$5,690,360.00	141%	\$8,016,110.00
	Accessory Electric Plant	\$8,432,242.00	157%	\$13,267,287.77
	I&C	\$6,955,160.00	153%	\$10,666,910.00
	Buildings & Structures	\$2,872,239.00	194%	\$5,581,951.17
	ZnO Polisher	\$500,000.00	185%	\$923,387.10
	Uninstalled Costs	\$314,120,189.64		
	Installed Costs	\$367,553,344.67		
	CO2 Compressors (7.38 MPa)	\$34,092,052.90		
	CO2 Pumps (15 MPa)	\$1,390,285.79		
	CO2 Storage (0 hrs)	\$0.00		
	CO2 Pipeline (94 mi)	\$80,248,238.84	CO2 Pipeline Mileage	94 mi
	CO2 Injection (1 well)	\$2,453,368.61		
	Costs of CO2 Disposal	\$118,183,946.13		
DepreciableCapital (Indirect)				
	(Component)	Cost		
	% of Uninstalled Costs	2.0%		
	% of Installed Costs	10%		
	Engineering & Design	\$0.00		
	Process Contingency	\$0.00		
	% of Installed Costs	15%		
	Project Contingency	\$0.00		
	Other Depreciable Capital	\$0.00		
	One-Time Licensing Fees	\$0.00		
	% of Uninstalled Costs	15%		
	Up-Front Permitting Costs	\$0.00		
VarLinear	DepreciableCapital	[\$]	(CY)	2050
Data	LandRequired	[acres]		\$631,026,059.21
VarData	FixedOM			250
FixedOM (Component)				
	(hours/year)	100		
	FTEs	100		
	[\$/hour]	\$50.00		
	Labor Costs	\$10,400,000.00		
	Overhead Labor Costs	20%		
	% of DepreciableCapital	2%		
	Property Tax & Insurance	\$0.00		
	Rent	\$0.00		
	[\$/year]	\$0.00		
	Lic. Permits and Fees	\$0.00		
	% of Installed Costs	0.6%		
	Matt for Maint. & Repairs	4.0%		
	% of Installed Costs	2.5%		
	Maint on CO2 Pipelines	\$ 108,541.19		
	Maint on CO2 Injection Wells	\$ 108,541.19		
	Other Fees	\$0.00		
	Other Fixed O&M Costs	\$0.00		
VarLinear	FixedOM	[\$/year]	(PY,CY)	2005 2050
Data	OtherFixed	[\$/year]		
VarLinear	FeedstockEfficiency			
Data	FeedstockEfficiency			
	(G,H,I)/GJfeedstock	Commercial Natural Gas	0.0000	0.0000
	(G,H,I)/GJfeedstock	Industrial Natural Gas	0.0000	0.0000
	(G,H,I)/GJfeedstock	Electric Utility Natural Gas	0.0000	0.0000
	(G,H,I)/GJ	Commercial Electricity	0.0000	0.0000
	(G,H,I)/GJ	Industrial Electricity	125.9039	125.9039
	(G,H,I)/GJfeedstock	Jubly Steam Coal (Central)	0.5925	0.5925
	(G,H,I)/GJfeedstock	Diesel Fuel	0.0000	0.0000
	(G,H,I)/GJfeedstock	Biomass	0.0000	0.0000
	(G,H,I)/GJfeedstock	Ethanol	0.0000	0.0000
	(G,H,I)/GJfeedstock	Methanol	0.0000	0.0000
	(G,H,I)/GJfeedstock	Gasoline	0.0000	0.0000
	(G,H,I)/GJfeedstock	Steam	0.0000	0.0000
	(G,H,I)/L	Cooling Water	0.0000	0.0000
	(G,H,I)/L	Demineralized Water	0.0000	0.0000
	(G,H,I)/L	Process Water	0.0108	0.0108
	(G,H,I)/Barrel	Bio-ol	0.0000	0.0000
	(G,H,I)/GJfeedstock	Jubly Steam Coal (Regional)	0.0000	0.0000
	(G,H,I)/GJfeedstock	MSW (1)	0.0000	0.0000
	(G,H,I)/GJfeedstock	MSW (2)	0.0000	0.0000
End	OtherVariableOM			
	(Component)	Cost		
	WT Costs	\$100,000.00		
	SHD Costs	\$796,000.00		
	Other Variable Op. Costs	\$2,747,000.00		
	Royalties	\$0.00		
	Operator Profit	\$0.00		
	Subsidies, Tax Incentives	\$0.00		
	Elect for CO2 Disposal	\$10,729,219.33		
	CO2 Separation & Seq.	\$0.00		
VarLinear	OtherVariableOM	[\$/kgH2]	(PY,CY)	2005 2050
Data	ByproductEfficiency			
VarLinear	Emissions			
Data	Emissions			
	(Species,CY)	Carbon	0	0
		GHG Equivalents	3.61	3.606828229
		NOX	0.008329699	0.008329699
		SOX	0	0
		Particulates (PM10)	0.001196463	0.001196463
		Mercury	0	0
End	ReplacementCosts	[\$]	(PY,CY)	2005 2050
Data	LearningFactor			
VarLinear	InitialUnitNo	[unit # in CYBegin]		500
VarData	LearningFactorStart			1
Building an upper-bound FC ought to decrease the cost of a normal FC by the same amount. You would probably want a similar Learning factor (maybe even a reference) on the normal FC sheet				

Variable	[Units]	(y-axis,x-axis)	Data	Source Used		
VarData	IClass		[1,1,1,5]			
VarData	OClass		[2,1,-1]			
VarData	CYStart	[Year]	2015			
VarData	CYStop	[Year]	2050			
Axis	CY		[2015-2050]			
VarData	IRR	[%]	10%			
VarData	DepreciationLength	[Years]	20			
VarData	AnalysisPeriod	[Years]	20			
VarData	Life	[Years]	40			
Axis	PY		[1-40]			
VarData	DesignCapacity	[kgH2/day]	316,289			
VarData	DesignCapacity	[kgH2/year]	115,445,485			
VarData	CapacityFactor	[% of DesignCapacity]	90%			
VarData	Location		1			
VarData	DepreciableCapital (Direct)	(Component)	Uninstalled Costs	Installation Factor	Installed Costs	
			Coal Handling Prep & Feed	155%	\$31,041,176.28	
			Feedwater & Misc. BOP Systems	147%	\$3,886,825.71	
			Gasifier & Accessories	138%	\$84,244,436.65	
			Air Separation Unit	100%	\$34,786,960.00	
			Hydrogen Separation & Gas Cleanup	100%	\$48,851,040.00	
			HRSG Ducting & Stack	118%	\$0.00	
			Steam Turbine Generator	122%	\$11,531,988.10	
			Cooling Water System	148%	\$6,369,490.00	
			Ash Handling System	141%	\$8,016,110.00	
			Accessory Electric Plant	157%	\$5,845,516.63	
			I&C	153%	\$10,666,910.00	
			Buildings & Structures	194%	\$5,972,927.09	
			Other		\$0.00	
			Uninstalled Costs		\$200,506,893.60	
			Installed Costs		\$251,213,380.47	
			CO2 Compressors (7.38 MPa)		\$34,091,721.72	
			CO2 Pumps (15 Mpa)		\$1,390,253.61	
			CO2 Storage (0 hrs)		\$0.00	
			CO2 Pipeline (94 mi)		\$80,247,554.23	
			CO2 Injection (1 well)		\$2,453,365.73	
			Costs of CO2 Disposal		\$118,182,895.30	
	DepreciableCapital (Indirect)	(Component)				
			% of Uninstalled Costs		1.2%	
			% of Installed Costs		10%	
			Engineering & Design		\$0.00	
			Process Contingency		\$0.00	
			% of Installed Costs		25%	
			Project Contingency		\$0.00	
			% of Installed Costs		15%	
			Other Depreciable Capital		\$0.00	
			One-Time Licensing Fees		\$0.00	
			Up-Front Permitting Costs		\$0.00	
VarLinear	DepreciableCapital	[\$]	(CY)	2015	2050	
Data				\$489,803,075.70	\$489,803,075.70	
VarData	LandRequired	[acres]		250		
VarData	FixedOM	(Component)				
			FTEs	100		
			Labor Costs	\$50.00		
			Labor Costs	\$10,400,000.00		
			% of Labor Cost	20%		
			% of DepreciableCapital	2%		
			Property Tax & Insurance	\$0.00		
			Rent	\$0.00		
			Lic. Permits and Fees	\$0.00		
			Mart for Maint. & Repairs	0.6%		
			% of Installed Costs			
			nt on CO2 Comp & Pumps	4.0%		
			% of Installed Costs			
			Maint on CO2 Pipelines	2.5%		
			% of Installed Costs			
			int on CO2 Injection Wells	\$ 108,540.30		
			Other Fees	\$0.00		
			Other Fixed O&M Costs	\$0.00		
VarLinear	FixedOM	[\$/year]	(PY,CY)	2015	2050	
Data				\$27,317,349.96	\$27,317,349.96	
End				\$27,317,349.96	\$27,317,349.96	
VarLinear	OtherFixed	[\$/year]	(PY,CY)	2015	2050	
Data				\$0.00	\$0.00	
End				\$0.00	\$0.00	
VarLinear	FeedstockEfficiency	(Feedstock,CY)		2015	2050	
Data				0.0000	0.0000	
			Commercial Natural Gas	0.0000	0.0000	
			Industrial Natural Gas	0.0000	0.0000	
			Electric Utility Natural Gas	0.0000	0.0000	
			Commercial Electricity	0.0000	0.0000	
			Industrial Electricity	0.0000	0.0000	
			Jillly Steam Coal (Central)	0.6091	0.6091	
			Diesel Fuel	0.0000	0.0000	
			Biomass	0.0000	0.0000	
			Ethanol	0.0000	0.0000	
			Methanol	0.0000	0.0000	
			Gasoline	0.0000	0.0000	
			Steam	0.0000	0.0000	
			Cooling Water	0.0000	0.0000	
			Deminerlized Water	0.0000	0.0000	
			Process Water	0.0101	0.0101	
			Bio-oil	0.0000	0.0000	
			lity Steam Coal (Regional)	0.0000	0.0000	
			MSW (1)	0.0000	0.0000	
			MSW (2)	0.0000	0.0000	
End				0.0000	0.0000	
	OtherVariableOM	(Component)				
			WT Costs	\$100,000.00		
			SWD Costs	\$796,000.00		
			Other Variable Op. Costs	\$1,029,000.00		
			Royalties	\$0.00		
			Operator Profit	\$0.00		
			Subsidies, Tax Incentives	\$0.00		
			Elect for CO2 Disposal	\$10,728,957.82		
			CO2 Separation & Seq.	\$0.00		
VarLinear	OtherVariableOM	[\$/kgH2]	(PY,CY)	2015	2050	
Data				\$0.1218	\$0.1218	
End				\$0.1218	\$0.1218	
VarLinear	ByproductEfficiency	(Byproduct,CY)		2015	2050	
Data				0.0000	0.0000	
End				0.0000	0.0000	
VarLinear	Emissions	[g/kgH2]	(Species,CY)			
Data				0	0	
			Carbon	0	0	
			GHG Equivalents	3.508489429	3.508489429	
			NOX	0	0	
			SOX	0	0	
			Particulates (PM10)	0	0	
			Mercury	0	0	
End				0	0	
VarLinear	ReplacementCosts	[\$]	(PY,CY)	2015	2050	
Data				\$2,449,015.38	\$2,449,015.38	
End				\$2,449,015.38	\$2,449,015.38	
VarLinear	LearningFactor	(Technology Factor)				
Data				1	5	
End				1	5	
VarData	InitialUnitNo	[unit # in CYBegin]		500		
VarData	LearningFactorStart			1		

Plant Description
Hot raw gas from the E-Gas gasifier is cooled and sent to the SCOHs process for desulfurization. Elemental sulfur is produced as a byproduct. The clean gas is filtered goes through a hydrogen separation membrane where the surface shift reaction occurs and hydrogen is separated from CO2. A portion of the hydrogen is fired to heat compressed air entering the ITM oxygen separation unit. Pure oxygen produced from the ITM is cooled and compressed for use in the gasifier. The remaining hydrogen is compressed for product delivery. The CO2-rich stream is fired with oxygen and expanded to recover energy as power. The CO2 exhaust is compressed for pipeline delivery.

CO2 separation is addressed with this equipment.

See Rows 125+ for CCSD equations.

Site Prep & Permitting Costs are % of Uninstalled Costs. This deviates from Reference 24 & 25. We believe Reference is in error.

H2A has this as a % of Depreciable Capital + LandCosts. We do not multiply by Land Costs because Land Costs are computer in MATLAB.

40gpm @ \$2500/yr-gpm
7600 tonne/yr @ \$10/tonne

Shift catalyst: Amine: & PSA, SO2 Catalyst Consumables.

Set to zero. H2A costs for this are covered in other categories on this worksheet.

0.5% of DepreciableCapital

Each row corresponds to a technology sheet. Building one of the current sheet will decrease the cost of every technology listed by the corresponding "Factor." The numbers in the first three columns are the 1st, 2nd and 4th numbers of the technology to be-changed's IClass var

All delivery (1-3) sheets with the same J share a LearningFactor (e.g., LT to 0.1TPD and LT to 1.1TPD only need one LearningFactor, since both sheets represent the same underlying technology - LT). The L for this common factor should always be 1, and the factor should appear on every sheet that shares it.

Building an upper-bound FC ought to decrease the cost of a normal FC by the same amount. You would probably want a similar LearningFactor (maybe even a reference) on the normal FC sheet

0	Variable	[Units]	(y-axis,x-axis)	Data	Source Used
VarData	IClass			[1,1,1,6]	
VarData	OClass			[2,1,-1]	
VarData	CYStart	[Year]		2025	
VarData	CYStop	[Year]		2050	
Axis	CY			[2025-2050]	
VarData	IRR	[%]		10%	
VarData	DepreciationLength	[Years]		20	
VarData	AnalysisPeriod	[Years]		20	
VarData	Life	[Years]		40	
Axis	PY			[1-40]	
VarData	DesignCapacity	[kgH2/day]		246,478	
VarData	DesignCapacity	[kgH2/year]		89,964,470	
VarData	CapacityFactor	(% of DesignCapacity)		90%	
VarData	Location			1	
	DepreciableCapital (Direct)	(Component)		Uninstalled Costs Installation Factor Installed Costs	
		Coal Handling Prep & Feed		\$22,881,589.63 155% \$35,459,650.02	25
		Feedwater & Misc. BOP Systems		\$6,401,057.14 147% \$9,412,307.14	25
		Gasifier & Accessories		\$50,541,901.49 138% \$69,800,373.62	25
		Air Separation Unit		\$34,786,960.00 146% \$50,786,960.00	25
		Hydrogen Separation & Gas Cleanup		\$53,972,240.00 100% \$53,972,240.00	25
		Expander/Generators & SOFC/CT		\$68,342,062.94 118% \$80,912,359.64	25
		HRSQ & Steam Turbine Generator		\$12,353,779.71 122% \$15,056,717.86	25
		Cooling Water System		\$1,582,749.31 148% \$2,345,668.04	25
		Ash Handling System		\$4,636,589.63 141% \$6,531,645.19	25
		Accessory Electric Plant		\$16,908,104.44 157% \$26,603,207.94	25
		I&C		\$8,422,406.68 153% \$12,917,180.06	25
		Buildings & Structures		\$3,254,656.75 194% \$6,325,147.41	25
		Uninstalled Costs		\$274,084,097.73	25
		Installed Costs		\$342,122,456.91	25
		CO2 Compressors (7.38 MPa)		\$34,092,424.61	23
		CO2 Pumps (15 MPa)		\$1,390,321.91	23
		CO2 Storage (0 hrs)		\$0.00	23
		CO2 Pipeline (94 mi)		\$80,249,007.22	23
		CO2 Injection (1 well)		\$2,453,371.83	23
		Costs of CO2 Disposal		\$118,185,125.57	23
	DepreciableCapital (Indirect)	(Component)			
		% of Uninstalled Costs		1.0%	25
		% of Installed Costs		10%	25
		Site Preparation		\$0.00	25
		Engineering & Design		\$0.00	25
		Process Contingency		\$0.00	25
		Project Contingency		25%	25
		Other Depreciable Capital		\$0.00	25
		One-Time Licensing Fees		\$0.00	25
		Up-Front Permitting Costs		10%	25
VarLinear	DepreciableCapital	[\$]		2025 2050	25
Data				\$610,199,693.15 \$610,199,693.15	
VarData	LandRequired	[acres]		250	25
	FixedOM	(Component)			
		FTEs		120	25
		Labor Costs		\$50.00	25
		Labor Costs		\$12,480,000.00	25
		% of Labor Cost		20%	25
		Property Tax & Insurance		2%	25
		Rent		\$0.00	25
		Lic., Permits and Fees		\$0.00	25
		Maint for Maint. & Repairs		0.6%	25
		Maint on CO2 Comp & Pumps		4.0%	23
		Maint on CO2 Pipelines		2.5%	23
		Maint on CO2 Injection Wells		\$ 108,542.20	23
		Other Fees		\$0.00	23
		Other Fixed O&M Costs		\$0.00	23
VarLinear	FixedOM	[\$/year]		2025 2050	
Data				\$32,766,805.85 \$32,766,805.85	
VarLinear	OtherFixed	[\$/year]		2025 2050	
Data				\$0.00 \$0.00	
VarLinear	FeedstockEfficiency	(Feedstock,CY)		2025 2050	
Data				0.0000 0.0000	
		Commercial Natural Gas		0.0000 0.0000	
		Industrial Natural Gas		0.0000 0.0000	
		Electric Utility Natural Gas		0.0000 0.0000	
		Commercial Electricity		0.0000 0.0000	
		Industrial Electricity		0.0000 0.0000	
		Utility Steam Coal (Central)		0.4746 0.4746	25
		Diesel Fuel		0.0000 0.0000	
		Biomass		0.0000 0.0000	
		Ethanol		0.0000 0.0000	
		Methanol		0.0000 0.0000	
		Gasoline		0.0000 0.0000	
		Steam		0.0000 0.0000	
		Cooling Water		0.0000 0.0000	
		Demineralized Water		0.0000 0.0000	
		Process Water		0.0108 0.0108	25
		Bio-oil		0.0000 0.0000	
		Utility Steam Coal (Regional)		0.0000 0.0000	
		MSW (1)		0.0000 0.0000	
		MSW (2)		0.0000 0.0000	
End	OtherVariableOM	(Component)			
		WT Costs		\$100,000.00	25
		SWD Costs		\$796,000.00	25
		Other Variable Op. Costs		\$1,029,000.00	25
		Royalties		\$0.00	25
		Operator Profit		\$0.00	25
		Subsidies, Tax Incentives		\$0.00	25
		Elect for CO2 Disposal		\$10,729,512.86	23
		CO2 Separation & Stg.		\$0.00	23
VarLinear	OtherVariableOM	[\$/kgH2]		2025 2050	
Data				\$0.1563 \$0.1563	
VarLinear	ByproductEfficiency	(Byproduct,CY)		2025 2050	
Data				-2.2799 -2.2799	
VarLinear	Emissions	(Species,CY)		2025 2050	
Data				0 0	
		Carbon		4.502446552 4.502446552	19
		GHG Equivalents		0 0	
		NOX		0 0	
		SOX		0 0	
		Particulates (PM10)		0 0	
		Mercury		0 0	
End	ReplacementCosts	[\$]		2025 2050	
VarLinear				\$3,050,998.47 \$3,050,998.47	
Data				\$3,050,998.47 \$3,050,998.47	
VarLinear	LearningFactor	(Technology,Factor)		1 5	
Data				1 5	
VarData	InitialUnitNo	[unit # in CYBegin]		500	
VarData	LearningFactorStart			1	

Plant Description

Hot raw gas from the transport gasifier is sent to the hot gas desulfurization process for desulfurization. Elemental sulfur is produced as a byproduct. The clean filtered hot gas then goes through a hydrogen separation membrane where the shift reaction occurs and hydrogen is separated from CO2. A portion of the hydrogen is fired to heat compressed air entering the ITM oxygen separation unit. Heat for the air is also extracted from the hot CO2 stream with a high temperature heat exchanger. Additional hydrogen is used to produce power from a combined cycle SOFC. Pure oxygen produced from the ITM is cooled and compressed for use in the gasifier. The remaining hydrogen is compressed for product delivery. The CO2 rich stream is fired with oxygen and expanded to recover energy as power. The CO2 exhaust is compressed for pipeline delivery.

CO2 separation is addressed with this equipment.

See Rows 125+ for CCSD equations.

Site Prep & Permitting Costs are % of Uninstalled Costs. This deviates from Reference 24 & 25. We believe Reference is in error.

H2A has this as a % of Depreciable Capital + Land/ Costs. We do not multiply by Land Costs because Land Costs are computed in MATLAB.

40gpm @ \$2500/yr-gpm

79600 tonnes/yr @ \$10/tonne

Shift catalyst: Amine: & PSA SO2 Catalyst Consumables

Set to zero. H2A costs for this are covered in other categories on this worksheet.

0.5% of DepreciableCapital

Each row corresponds to a technology sheet. Building one of the current sheet will decrease the cost of every technology listed by the corresponding "factor". The numbers in the first three columns are the 1st, 2nd and 4th numbers of the technology to be cheapened's IClass var

All delivery (1-3) sheets with the same I share a LearningFactor (e.g., LT to 0.1TRD and LT to 1.5TRD only need one LearningFactor, since both sheets represent the same underlying technology - LTs). The L for this common factor should always be 1, and the factor should appear on every sheet that shares it.

Building an upper-bound FC ought to decrease the cost of a normal FC by the same amount. You would probably want a similar LearningFactor (maybe even a reference) on the normal FC sheet

Variable	[Units]	(y-axis,x-axis)	Data	Source Used		
IClass			[1,1,1,7]			
OClass			[2,1,-1]			
CYStart	[Year]		2005	19		
CYStop	[Year]		2050			
CY	[CY]		[2005,2050]			
IRR	[%]	After-Tax, Real IRR	10%	18		
DepreciationLength	[Years]		20	18		
AnalysisPeriod	[Years]		20			
Life	[Years]		40	18		
PY	[PY]		[1,40]			
DesignCapacity	[kgH2/day]		283,830	18		
DesignCapacity	[kgH2/year]		103,597,990			
CapacityFactor	[% of DesignCapacity]		90%	18		
Location			4			
DepreciableCapital (Direct)	(Component)	Uninstalled Costs	Installation Factor	Installed Costs		
		Coal Handling Prep & Feed	\$20,030,413.64	155%	\$31,041,176.28	18
		Feedwater & Misc. BOP Systems	\$3,615,840.00	147%	\$5,316,840.00	18
		Gasifier & Accessories	\$61,000,733.91	138%	\$84,244,436.65	18
		Air Separation Unit	\$58,523,040.00	100%	\$58,523,040.00	18
		Hydrogen Separation & Gas Cleanup	\$55,393,280.00	100%	\$55,393,280.00	18
		HRSQ Ducting & Stack	\$15,896,800.00	118%	\$18,776,950.00	18
		Steam Turbine Generator	\$12,938,160.00	122%	\$15,767,910.00	18
		Cooling Water System	\$4,297,840.00	148%	\$6,369,490.00	18
		Ash Handling System	\$5,690,360.00	141%	\$8,016,110.00	18
		Accessory Electric Plant	\$7,800,840.00	157%	\$12,273,840.00	18
		I&C	\$6,955,160.00	153%	\$10,666,910.00	18
		Buildings & Structures	\$3,073,418.88	194%	\$5,972,927.09	18
		Zinc Oxide Polisher	\$310,000.00	185%	\$572,500.00	18
		Uninstalled Costs	\$255,525,886.44			
		Installed Costs	\$312,935,410.02			
DepreciableCapital (Indirect)	(Component)					
	[% of Uninstalled Costs]	Site Preparation	2%			18
	[% of Installed Costs]	Engineering & Design	10%			18
	[\$]	Process Contingency	\$0.00			
	[% of Installed Costs]	Project Contingency	15%			18
	[\$]	Other Depreciable Capital	\$0.00			
	[\$]	One-Time Licensing Fees	\$0.00			
	[% of Uninstalled Costs]	Up-Front Permitting Costs	15%			18
DepreciableCapital	[\$]	(CY)	2005	2050		
			\$434,608,663.22	\$434,608,663.22		
LandRequired	[acres]		250			18
FixedOM	(Component)					
	(hours/year)	FTEs	100			18
	[\$/hour]	Labor Costs	\$50.00			18
	[\$/year]	Labor Costs	\$10,400,000.00			18
	[% of Labor Cost]	Overhead and Profit	20%			18
	[% of DepreciableCapital]	Property Tax & Insurance	2%			18
	[\$/year]	Rent	\$0.00			
	[\$/year]	Lic., Permits and Fees	\$0.00			
	[% of Installed Costs]	Matl for Maint. & Repairs	0.6%			18
	[\$/year]	Other Fees	\$0.00			
	[\$/year]	Other Fixed O&M Costs	\$0.00			
FixedOM	[\$/year]	(PY,CY)	2005	2050		
			\$23,049,785.72	\$23,049,785.72		
OtherFixed	[\$/year]	(PY,CY)	2005	2050		
			\$0.00	\$0.00		
FeedstockEfficiency	(Feedstock,CY)	2005	2050			
	(GJH2/GJFeedstock)	Commercial Natural Gas	0.0000	0.0000		
	(GJH2/GJFeedstock)	Industrial Natural Gas	0.0000	0.0000		
	(GJH2/GJFeedstock)	Electric Utility Natural Gas	0.0000	0.0000		
	(GJH2/GJ)	Commercial Electricity	0.0000	0.0000		
	(GJH2/GJ)	Industrial Electricity	0.0000	0.0000		
	(GJH2/GJFeedstock)	Utility Steam Coal (Central)	0.5466	0.5466		18
	(GJH2/GJFeedstock)	Diesel Fuel	0.0000	0.0000		
	(GJH2/GJFeedstock)	Biomass	0.0000	0.0000		
	(GJH2/GJFeedstock)	Ethanol	0.0000	0.0000		
	(GJH2/GJFeedstock)	Methanol	0.0000	0.0000		
	(GJH2/GJFeedstock)	Gasoline	0.0000	0.0000		
	(GJH2/GJFeedstock)	Steam	0.0000	0.0000		
	(GJH2/L)	Cooling Water	0.0000	0.0000		
	(GJH2/L)	Demineralized Water	0.0000	0.0000		
	(GJH2/L)	Process Water	0.0108	0.0108		18
	(GJH2/Barrel)	Bio-oil	0.0000	0.0000		
	(GJH2/GJFeedstock)	Utility Steam Coal (Regional)	0.0000	0.0000		
	(GJH2/GJFeedstock)	MSW (1)	0.0000	0.0000		
	(GJH2/GJFeedstock)	MSW (2)	0.0000	0.0000		
OtherVariableOM	(Component)					
	[\$/year] @ capacity	WT Costs	\$101,000.00			18
	[\$/year] @ capacity	SWD Costs	\$894,000.00			18
	[\$/year] @ capacity	Other Variable Op. Costs	\$2,417,000.00			18
	[\$/year] @ capacity	Royalties	\$0.00			
	[\$/year] @ capacity	Operator Profit	\$0.00			
	[\$/year] @ capacity	Subsidies, Tax Incentives	\$0.00			
	[\$/year] @ capacity	CO2 Separation & Seq.	\$0.00			
OtherVariableOM	[\$/kgH2]	(PY,CY)	2005	2050		
			\$0.0366	\$0.0366		
ByproductEfficiency	(Byproduct,CY)	2005	2050			
	(GJH2/GJ)	Byproduct Electricity	-10.6275	-10.6275		18
	(GJH2/GJFeedstock)	Steam	0.0000	0.0000		
Emissions	(Species,CY)	2005	2050			
		Carbon	0	0		19
		GHG Equivalents	22.60383793	22.60383793		
		NOx	0	0		
		SOx	0	0		
		Particulates (PM10)	0	0		
		Mercury	0	0		
ReplacementCosts	[\$]	(PY,CY)	2005	2050		
			\$2,173,043.32	\$2,173,043.32		18
LearningFactor	(Technology,Factor)	IClass[1] (I)	IClass[2] (J)	IClass[4] (L)	Factor	
		FC,NG-SMR,1.5 (UPPER)	1	5	2	1
		FC,NG-SMR,1.5	1	5	2	1
InitialUnitNo	[Unit # in CYBegin]		500			
LearningFactorStart			1			

Plant Description

To arrive at a cost estimate for hydrogen, the design included commercially available process technology obtained from verifiable sources. The plant utilized commercially available technology including a Wabash River-scale Conoco-Phillips (IGas) gasifier, conventional gas cooling, commercial shift conversion and acid gas cleanup, commercial sulfuric acid technology, and commercial pressure swing adsorption (PSA). The IGas gasifier is the gasifier of choice for this study since it has been operated on both bituminous and sub-bituminous coals.

H2A has this as a % of DepreciableCapital+LandCosts. We do not multiply by Land Costs because Land Costs are computer in MATLAB.

0.5% of DepreciableCapital

Each row corresponds to a technology sheet. Building one of the current sheet will decrease the cost of every technology listed by the corresponding "Factor." The numbers in the first three columns are the 1st, 2nd and 4th numbers of the technology to be Chapman's IClass var

All delivery (1-3) sheets with the same J share a LearningFactor (e.g., LT to 0.1TPD and LT to 1.5TPD only need one LearningFactor, since both sheets represent the same underlying technology - 1LT). The L for this common factor should always be 1, and the factor should appear on every sheet that shares it.

Building an upper-bound FC ought to decrease the cost of a normal FC by the same amount. You would probably want a similar LearningFactor (maybe even a reference) on the normal FC sheet

Plant Description
To arrive at a cost estimate for hydrogen, the design included commercially available process technology obtained from verifiable sources. The plant utilized commercially available technology including a Wabash River-scale Conoco-Phillips (EGS) gasifier, conventional gas cooling, commercial shift conversion and acid gas cleanup, commercial sulfuric acid technology, and commercial pressure swing absorption (PSA). The EGS gasifier is the gasifier of choice for this study since it has been operated on both bituminous and sub-bituminous coals.

H2A has this as a % of DepreciableCapital-LandCosts. We do not multiply by Land Costs because Land Costs are computer in MATLAB.

0.5% of DepreciableCapital
Each row corresponds to a technology sheet. Building one of the current sheet will decrease the cost of every technology listed by the corresponding "Factor." The numbers in the first three columns are the 1st, 2nd and 4th numbers of the technology to be cheapened's IClass var

All delivery (I=3) sheets with the same J share a LearningFactor (e.g., LT to 0.1TPD and LT to 1.5TPD only need one LearningFactor, since both sheets represent the same underlying technology - LTs). The L for this common factor should always be 1, and the factor should appear on every sheet that shares it.

Building an upper-bound FC ought to decrease the cost of a normal FC by the same amount. You would probably want a similar LearningFactor (maybe even a reference) on the normal FC sheet

0	Variable	[Units]	(y-axis,x-axis)	Data	Source Used
VarData	IClass			[1,1,1,8]	
VarData	OClass			[2,1,-1]	
VarData	CYStart	[Year]		2015	20
VarData	CYStop	[Year]		2050	
Axis	CY	CY		[2015-2050]	
VarData	IRR	[%]		10%	20
VarData	DepreciationLength	[Years]		20	20
VarData	AnalysisPeriod	[Years]		20	
VarData	Life	[Years]		40	20
Axis	PY	PY		[1-40]	
VarData	DesignCapacity	[kgH2/day]		316,299	20
VarData	DesignCapacity	[kgH2/year]		115,445,485	
VarData	CapacityFactor	[% of DesignCapacity]		90%	20
VarData	Location			-4	
Plant Description Hot raw gas from the E-Gas gasifier is cooled and sent to the SODS process for desulfurization. Elemental sulfur is produced as a byproduct. The clean gas is filtered goes through a hydrogen separation membrane where the surface shift reaction occurs and hydrogen is separated from CO2. A portion of the hydrogen is fired to heat compressed air entering the TM oxygen separation unit. Pure oxygen produced from the TM is cooled and compressed for use in the gasifier. The remaining hydrogen is compressed for product delivery. The CO2-rich stream is fired with oxygen and expanded to recover energy as power.					
DepreciableCapital (Direct) (Component) Uninstalled Costs Installation Factor Installed Costs					
	Coal Handling Prep & Feed			\$20,030,413.64	20
	Feedwater & Misc. BOP Systems			\$2,643,325.71	20
	Gasifier & Accessories			\$61,000,733.91	20
	Air Separation Unit			\$34,786,960.00	20
	Hydrogen Separation & Gas Cleanup			\$48,851,040.00	20
	HRSO Ducting & Stack			\$0.00	20
	Steam Turbine Generator			\$9,462,427.63	20
	Cooling Water System			\$4,297,840.00	20
	Ash Handling System			\$5,690,360.00	20
	Accessory Electric Plant			\$3,715,213.82	20
	I&C			\$6,955,160.00	20
	Buildings & Structures			\$3,073,418.88	20
	Other			\$0.00	20
	Uninstalled Costs			\$200,506,893.60	
	Installed Costs			\$251,213,380.47	
DepreciableCapital (Indirect) (Component) Site Preparation Engineering & Design Process Contingency Project Contingency Other Depreciable Capital One-Time Licensing Fees Up-Front Permitting Costs					
	[% of Uninstalled Costs]			1.2%	20
	[% of Installed Costs]			10%	20
	[% of Installed Costs]			\$0.00	20
	[% of Installed Costs]			25%	20
	[% of Installed Costs]			\$0.00	20
	[% of Installed Costs]			\$0.00	20
	[% of Installed Costs]			15%	20
VarLinear	DepreciableCapital	[\$]	(CY)	2015	20
VarData	LandRequired	[acres]		250	20
FixedOM (Component) FTEs Labor Costs Property Tax & Insurance Rent Lic., Permits and Fees Matl for Maint. & Repairs Other Fees Other Fixed O&M Costs					
	Hours/year			100	20
	\$/hour			\$50.00	20
	\$/year			\$10,400,000.00	20
	[% of Labor Cost]			20%	20
	[% of DepreciableCapital]			2%	20
	\$/year			\$0.00	20
	\$/year			\$0.00	20
	[% of Installed Costs]			0.6%	20
	\$/year			\$0.00	20
	\$/year			\$0.00	20
VarLinear	FixedOM	[\$/year]	(PY,CY)	2015	20
Data				\$21,419,683.88	
End				\$21,419,683.88	
VarLinear	OtherFixed	[\$/year]	(PY,CY)	2015	20
Data				\$0.00	
End				\$0.00	
VarLinear	FeedstockEfficiency		(Feedstock,CY)	2015	20
Data				0.0000	
	[GJH2/GJFeedstock]			0.0000	
	[GJH2/GJFeedstock]			0.0000	
	[GJH2/GJFeedstock]			0.0000	
	[GJH2/GJ]			0.0000	
	[GJH2/GJ]			0.0000	
	[GJH2/GJFeedstock]			0.6091	20
	[GJH2/GJFeedstock]			0.0000	
	[GJH2/GJFeedstock]			0.0000	
	[GJH2/GJFeedstock]			0.0000	
	[GJH2/GJFeedstock]			0.0000	
	[GJH2/GJFeedstock]			0.0000	
	[GJH2/GJ]			0.0000	
	[GJH2/GJ]			0.0000	
	[GJH2/GJ]			0.0101	20
	[GJH2/GJ]			0.0000	
	[GJH2/GJFeedstock]			0.0000	
	[GJH2/GJFeedstock]			0.0000	
End				0.0000	
OtherVariableOM (Component) WT Costs SWD Costs Other Variable Op. Costs Royalties Operator Profit Subsidies, Tax Incentives CO2 Separation & Seq.					
	\$/year @ capacity			\$100,000.00	20
	\$/year @ capacity			\$796,000.00	20
	\$/year @ capacity			\$1,029,000.00	20
	\$/year @ capacity			\$0.00	
	\$/year @ capacity			\$0.00	
	\$/year @ capacity			\$0.00	
	\$/year @ capacity			\$0.00	
VarLinear	OtherVariableOM	[\$/kgH2]	(PY,CY)	2015	20
Data				\$0.0185	
End				\$0.0185	
VarLinear	ByproductEfficiency		(Byproduct,CY)	2015	20
Data				-168,7113	
End				0.0000	
VarLinear	Emissions	[kg/kgH2]	(Species,CY)	2015	20
Data				0	
	Carbon			0	
	GHG Equivalents			20,28447375	19
	NOX			0	
	SOX			0	
	Particulates (PM10)			0	
	Mercury			0	
End				0	
VarLinear	ReplacementCosts	[\$]	(PY,CY)	2015	20
Data				\$1,858,100.90	
End				\$1,858,100.90	
Var	LearningFactor		(Technology, Factor)	FC,NG-SMR,1.5 (UPPER)	20
Data				1	
End				5	
VarData	InitialUnitNo	[unit # in CYBegin]		500	
VarData	LearningFactorStart			1	

	Variable	[Units]	(y-axis,x-axis)	Data	Source Used
VarData	IClass			[1,1,1,9]	
VarData	OClass			[2,1,-1]	
VarData	CYStart	[Year]		2025	21
VarData	CYStop	[Year]		2050	
Axis	CY	CY		[2025:2050]	
VarData	IRR	[%]		10%	21
VarData	DepreciationLength	[Years]		20	21
VarData	AnalysisPeriod	[Years]		20	
VarData	Life	[Years]		40	21
Axis	PY	PY		[1:40]	
VarData	DesignCapacity	[kgH2/day]		246.478	
VarData	DesignCapacity	[kgH2/year]		89,964.470	21
VarData	CapacityFactor	[% of DesignCapacity]		90%	21
VarData	Location			-4	
DepreciableCapital (Direct)				(Component)	
	Coal Handling Prep & Feed			Uninstalled Costs \$22,881,589.63 Installation Factor 55% Installed Costs \$35,459,650.02	21
	Feedwater & Misc. BOP Systems			\$6,401,057.14 147% \$9,412,307.14	21
	Gasifier & Accessories			\$50,541,901.49 138% \$69,800,373.62	21
	Air Separation Unit			\$34,786,960.00 100% \$34,786,960.00	21
	Hydrogen Separation & Gas Cleanup			\$53,972,240.00 100% \$53,972,240.00	21
	Expander/Generators & SOFC/CT			\$58,342,062.94 118% \$68,912,359.64	21
	HRSO & Steam Turbine Generator			\$12,353,779.71 122% \$15,056,717.86	21
	Cooling Water System			\$1,582,749.31 148% \$2,345,668.04	21
	Ash Handling System			\$4,636,589.63 141% \$6,531,645.19	21
	Accessory Electric Plant			\$16,908,104.44 157% \$26,603,207.94	21
	I&C			\$8,422,406.68 153% \$12,917,180.06	21
	Buildings & Structures			\$3,254,656.75 194% \$6,325,147.41	21
DepreciableCapital (Indirect)				(Component)	
	Uninstalled Costs			\$274,084,097.73	
	Installed Costs			\$342,122,456.91	
	[% of Uninstalled Costs]			1.0%	21
	Site Preparation				
	[% of Installed Costs]			10%	21
	Engineering & Design				
	Process Contingency			\$0.00	
	Project Contingency			25%	21
	Other Depreciable Capital			\$0.00	
	One-Time Licensing Fees			\$0.00	
	Up-Front Permitting Costs			10%	
VarLinear	DepreciableCapital	[\$]		2025 2050	21
Data				\$462,014,567.55 \$462,014,567.55	
VarData	LandRequired	[acres]		250	21
FixedOM				(Component)	
	FTEs			120	21
	Labor Costs			\$50.00	21
	Labor Costs			\$12,480,000.00	
	[% of Labor Cost]			20%	21
	Property Tax & Insurance			2%	21
	Rent			\$0.00	
	Lic., Permits and Fees			\$0.00	
	Maint for Maint. & Repairs			0.6%	21
	Other Fees			\$0.00	
	Other Fixed O&M Costs			\$0.00	
VarLinear	FixedOM	[\$/year]		(PY,CY)	2025 2050
Data				1 \$26,869,026.09 \$26,869,026.09	
End				40 \$26,869,026.09 \$26,869,026.09	
VarLinear	OtherFixed	[\$/year]		(PY,CY)	2025 2050
Data				1 \$0.00 \$0.00	
End				40 \$0.00 \$0.00	
VarLinear	FeedstockEfficiency			(Feedstock,CY)	2025 2050
Data				1 0.0000 0.0000	
End				40 0.0000 0.0000	
	[GJH2/GJFeedstock]			Commercial Natural Gas 0.0000 0.0000	
	[GJH2/GJFeedstock]			Industrial Natural Gas 0.0000 0.0000	
	[GJH2/GJFeedstock]			Electric Utility Natural Gas 0.0000 0.0000	
	[GJH2/GJFeedstock]			Commercial Electricity 0.0000 0.0000	
	[GJH2/GJFeedstock]			Industrial Electricity 0.0000 0.0000	
	[GJH2/GJFeedstock]			Utility Steam Coal (Central) 0.4746 0.4746	21
	[GJH2/GJFeedstock]			Diesel Fuel 0.0000 0.0000	
	[GJH2/GJFeedstock]			Biomass 0.0000 0.0000	
	[GJH2/GJFeedstock]			Ethanol 0.0000 0.0000	
	[GJH2/GJFeedstock]			Methanol 0.0000 0.0000	
	[GJH2/GJFeedstock]			Gasoline 0.0000 0.0000	
	[GJH2/GJFeedstock]			Steam 0.0000 0.0000	
	[GJH2/L]			Cooling Water 0.0000 0.0000	
	[GJH2/L]			Demineralized Water 0.0000 0.0000	
	[GJH2/L]			Process Water 0.0108 0.0108	21
	[GJH2/Barrel]			Bio-oil 0.0000 0.0000	
	[GJH2/GJFeedstock]			ity Steam Coal (Regional) 0.0000 0.0000	
	[GJH2/GJFeedstock]			MSW (1) 0.0000 0.0000	
	[GJH2/GJFeedstock]			MSW (2) 0.0000 0.0000	
OtherVariableOM				(Component)	
	WT Costs			\$100,000.00	21
	SWD Costs			\$796,000.00	21
	Other Variable Op. Costs			\$1,029,000.00	21
	Royalties			\$0.00	
	Operator Profit			\$0.00	
	Subsidies, Tax Incentives			\$0.00	
	CO2 Separation & Seq.			\$0.00	
VarLinear	OtherVariableOM	[\$/kgH2]		(PY,CY)	2025 2050
Data				1 \$0.0238 \$0.0238	
End				40 \$0.0238 \$0.0238	
VarLinear	ByproductEfficiency			(Byproduct,CY)	2025 2050
Data				1 -2.2450 -2.2450	
End				40 0.0000 0.0000	
VarLinear	Emissions	[kg/kgH2]		(Species,CY)	2025 2050
Data				1 0 0	
End				40 26.03107711 26.03107711	19
	Carbon				
	GHG Equivalents				
	NOx				
	SOx				
	Particulates (PM10)				
	Mercury				
VarLinear	ReplacementCosts	[\$]		(PY,CY)	2025 2050
Data				1 \$2,460,072.84 \$2,460,072.84	21
End				40 \$2,460,072.84 \$2,460,072.84	
Var	LearningFactor			(Technology, Factor)	
Data				FC,NG-SMR,1.5 (UPPER) 1 5 3	
End				FC,NG-SMR,1.5 1 6 2	
VarData	InitialUnitNo	[Unit # in CYBegin]		500	
VarData	LearningFactorStart			1	

Plant Description
Hot raw gas from the transport gasifier is sent to the hot gas desulfurization process for desulfurization. Elemental sulfur is produced as a byproduct. The clean filtered hot gas then goes through a hydrogen separation membrane where the shift reaction occurs and hydrogen is separated from CO2. A portion of the hydrogen is fired to heat compressed air entering the ITM oxygen separation unit. Heat for the air is also extracted from the hot CO2 stream with a high temperature heat exchanger. Additional hydrogen is used to produce power from a combined cycle SOFC. Pure oxygen produced from the ITM is cooled and compressed for use in the gasifier. The remaining hydrogen is compressed for product delivery. The CO2-rich stream is fired with oxygen and expanded to recover energy as power.

Site Prep & Permitting Costs are % of Uninstalled Costs. This deviates from Reference 20 & 21. We believe Reference is in error.

H2A has this as a % of Depreciable Capital + LandCosts. We do not multiply by Land Costs because Land Costs are computer in MATLAB.

40gpm @ \$2500/yr-gpm

79600 tonne/yr @ \$10/tonne

Shift catalyst: Amine: & PSA, SO2 Catalyst Consumables

0.5% of DepreciableCapital

Each row corresponds to a technology sheet. Building one of this current sheet will decrease the cost of every technology listed by the corresponding "Factor." The numbers in the first three columns are the 1st, 2nd and 4th numbers of the technology to-be-changed's IClass var

All delivery (1-3) sheets with the same J share a LearningFactor (e.g., LT to 0.1TPD and LT to 1.5TPD only need one LearningFactor, since both sheets represent the same underlying technology - LTs). The L for this common factor should always be 1, and the factor should appear on every sheet that shares it.

Building an upper-bound FC ought to decrease the cost of a normal FC by the same amount. You would probably want a similar LearningFactor (maybe even a reference) on the normal FC sheet

0	Variable	(Units)	(y-axis,x-axis)	Data	Source Used
VarData	IClass			[1,1,1,0]	
VarData	OClass			[2,1,-1]	
VarData	CYStart	[Year]		2005	22
VarData	CYStop	[Year]		2050	
Axis	CY	CY		[2005,2050]	
VarData	IRR	[%]		10%	22
VarData	DepreciationLength	[Years]		20	22
VarData	AnalysisPeriod	[Years]		20	
VarData	Life	[Years]		40	22
Axis	PY	PY		[1,40]	
VarData	DesignCapacity	[kgH2/day]		307.673	22
VarData	DesignCapacity	[kgH2/year]		112,300,645	
VarData	CapacityFactor	[% of DesignCapacity]		90%	22
VarData	Location				
DepreciableCapital (Direct) (Component) Uninstalled Costs Installation Factor Installed Costs					
	Coal Handling Prep & Fees			\$20,030,413.64	22
	Feedwater & Misc. BOP Systems			\$3,615,840.00	22
	Gasifier & Accessories			\$51,415,039.00	22
	Air Separation Unit			\$77,509,920.00	22
	Hydrogen Separation & Gas Cleanup			\$108,312,840.00	22
	HRSG Ducting & Stack			\$15,896,800.00	22
	Steam Turbine Generator			\$11,137,717.00	22
	Cooling Water System			\$3,751,819.00	22
	Ash Handling System			\$5,690,360.00	22
	Accessory Electric Plant			\$8,432,242.00	22
	I&C			\$6,955,160.00	22
	Buildings & Structures			\$2,872,239.00	22
	ZnO Polisher			\$500,000.00	22
	Uninstalled Costs			\$314,120,199.64	22
	Installed Costs			\$367,553,344.67	22
	CO2 Compressors (7.38 MPa)			\$34,092,052.90	23
	CO2 Pumps (15 MPa)			\$1,390,285.79	23
	CO2 Storage (0 hrs)			\$0.00	
	CO2 Pipeline (94 mi)			\$80,248,238.84	23
	CO2 Injection (1 well)			\$2,453,368.61	23
	Costs of CO2 Disposal			\$118,183,946.13	
DepreciableCapital (Indirect) (Component) % of Uninstalled Costs % of Installed Costs [\$]					
	Site Preparation			2.0%	22
	Engineering & Design			10%	22
	Process Contingency			\$0.00	
	Project Contingency			15%	22
	Other Depreciable Capital			\$0.00	
	One-Time Licensing Fees			\$0.00	
	Up-Front Permitting Costs			15%	22
VarLinear	DepreciableCapital	[\$]		2005	
Data				\$631,026,059.21	
VarData	LandRequired	[acres]		250	22
FixedOM (Component) [hours/year] [\$/hour] [\$/year]					
	FTEs			100	22
	Labor Costs			\$50.00	22
	Labor Costs			\$10,400,000.00	
	Overhead and G&A			20%	
	Property Tax & Insurance			2%	22
	Rent			\$0.00	
	Lic. Permits and Fees			\$0.00	
	Maint for Maint. & Repairs			0.6%	22
	Maint on CO2 Comp & Pumps			4.0%	23
	Maint on CO2 Pipelines			2.5%	23
	Maint on CO2 Injection Wells			\$ 108,541.19	23
	Other Fees			\$0.00	
	Other Fixed O&M Costs			\$0.00	
VarLinear	FixedOM	[\$/year]		2005	
Data				\$30,839,881.96	
End				\$30,839,881.96	
VarLinear	OtherFixed	[\$/year]		2005	
Data				\$0.00	
End				\$0.00	
VarLinear	FeedstockEfficiency			2005	
Data				0.0000	
	Commercial Natural Gas			0.0000	
	Industrial Natural Gas			0.0000	
	Electric Utility Natural Gas			0.0000	
	Commercial Electricity			0.0000	
	Industrial Electricity			125.9039	22
	Jillit Steam Coal (Central)			0.5925	22
	Diesel Fuel			0.0000	
	Biomass			0.0000	
	Ethanol			0.0000	
	Methanol			0.0000	
	Gasoline			0.0000	
	Steam			0.0000	
	Cooling Water			0.0000	
	Demineralized Water			0.0000	
	Process Water			0.0108	22
	Bio-oil			0.0000	
	Jillit Steam Coal (Regional)			0.0000	
	MSW (1)			0.0000	
	MSW (2)			0.0000	
OtherVariableOM (Component) [\$/year] @ capacity WT Costs SWD Costs Other Variable Op. Costs Royalties Operator Profit Subsidies, Tax Incentives Elect for CO2 Disposal CO2 Separation & Sec					
	WT Costs			\$100,000.00	22
	SWD Costs			\$796,000.00	22
	Other Variable Op. Costs			\$2,747,000.00	22
	Royalties			\$0.00	
	Operator Profit			\$0.00	
	Subsidies, Tax Incentives			\$0.00	
	Elect for CO2 Disposal			\$10,729,219.33	23
	CO2 Separation & Sec			\$0.00	22
VarLinear	OtherVariableOM	[\$/kgH2]		2005	
Data				\$0.1422	
End				\$0.1422	
VarLinear	ByproductEfficiency			2005	
Data				0.0000	
End				0.0000	
VarLinear	Emissions	[kg/kgH2]		2005	
Data				0	
	GHG Equivalent			3.606828229	19
	NOx			0.008329899	7
	SOx			0	
	Particulates (PM10)			0.001196463	7
	Mercury			0	
End				0	
VarLinear	ReplacementCosts	[\$]		2005	
Data				\$3,155,130.30	
End				\$3,155,130.30	
Var	LearningFactor			40	22
Data				1	
End				5	
VarData	InitialUnitNo	[unit # in CYBegin]		500	
VarData	LearningFactorStart			1	

Plant Description
To arrive at a cost estimate for hydrogen, the design included commercially available process technology obtained from verifiable sources. The plant utilized commercially available technology including a Wabash River-scale Destec (EGas) gasifier, conventional gas cooling, commercial shift conversion and acid gas cleanup, commercial sulfuric acid technology, and commercial pressure swing absorption (PSA). Two-stage Selectol is used to remove CO2. CO2 is compressed to 2200 psi for sequestration. The Gas gasifier is the gasifier of choice for this study since it has been operated on both bituminous and sub-bituminous coals.

CO2 separation is addressed with this equipment.

See Rows 125+ for CCSD equations.

H2A has this as a % of Depreciable Capital + Land Costs. We do not multiply by Land Costs because Land Costs are computer in MATLAB.

40gpm @ \$2500/yr-gpm

75600 tonne/yr @ \$10/tonne

Shift catalyst, 507 lb/d @ \$5.24; Amine, 288 lb/d @ \$1.00/lb; & PSA, Consumables

Set to zero. H2A costs for this are covered in other categories on this worksheet.

0.5% of DepreciableCapital

Each row corresponds to a technology sheet. Building one of the current sheet will decrease the cost of every technology listed by the corresponding "Factor". The numbers in the first three columns are the 1st, 2nd and 4th numbers of the technology to be cheapened's IClass var

All delivery (1-3) sheets with the same J share a LearningFactor (e.g., LT to 0.11PD and LT to 1.51PD only need one LearningFactor, since both sheets represent the same underlying technology - LTs). The L for this common factor should always be 1, and the factor should appear on every sheet that shares it.

Building an upper-bound FC ought to decrease the cost of a normal FC by the same amount. You would probably want a similar LearningFactor (maybe even a reference) on the normal FC sheet

Variable	[Units]	(y-axis,x-axis)	Data	Plant Description	Source Used		
VarData	IClass		[1,1,1,1]	Hot raw gas from the F-Gas gasifier is cooled and sent to the SCOH process for desulfurization. Elemental sulfur is produced as a byproduct. The clean gas is filtered goes through a hydrogen separation membrane where the surface shift reaction occurs and hydrogen is separated from CO2. A portion of the hydrogen is fired to heat compressed air entering the ITM oxygen separation unit. Pure oxygen produced from the ITM is cooled and compressed for use in the gasifier. The remaining hydrogen is compressed for product delivery. The CO2-rich stream is fired with oxygen and expanded to recover energy as power. The CO2 exhaust is compressed for pipeline delivery.			
VarData	OClass		[2,1,-1]				
VarData	CYStart	[Year]	2015		24		
VarData	CYStop	[Year]	2050				
Axis	CY		[2015:2050]				
VarData	IRR	[%]	10%		24		
VarData	DepreciationLength	[Years]	20		24		
VarData	AnalysisPeriod	[Years]	20				
VarData	Life	[Years]	40		24		
Axis	PY		[1:40]				
VarData	DesignCapacity	[kgH2/day]	316,289	24			
VarData	DesignCapacity	[kgH2/year]	115,445,485				
VarData	CapacityFactor	[% of DesignCapacity]	90%	24			
VarData	Location		-4				
DepreciableCapital (Direct)			(Component)	Uninstalled Costs	Installation Factor	Installed Costs	
			Coal Handling Prep & Feed	\$20,030,413.64	155%	\$31,041,176.28	24
			Feedwater & Misc. BOP Systems	\$2,643,325.71	147%	\$3,886,825.71	24
			Gasifier & Accessories	\$61,000,733.91	138%	\$84,244,436.65	24
			Air Separation Unit	\$34,786,960.00	100%	\$34,786,960.00	24
			Hydrogen Separation & Gas Cleanup	\$48,851,040.00	100%	\$48,851,040.00	24
			HRSG Ducting & Stack	\$0.00	118%	\$0.00	24
			Steam Turbine Generator	\$9,462,427.63	122%	\$11,531,988.10	24
			Cooling Water System	\$4,297,840.00	148%	\$6,369,490.00	24
			Ash Handling System	\$5,690,360.00	141%	\$8,016,110.00	24
			Accessory Electric Plant	\$3,715,213.82	157%	\$5,845,516.63	24
			I&C	\$6,955,160.00	153%	\$10,666,910.00	24
			Buildings & Structures	\$3,073,418.88	194%	\$5,972,927.09	24
			Other	\$0.00	185%	\$0.00	24
			Uninstalled Costs	\$200,506,893.60			
			Installed Costs	\$251,213,380.47			
			CO2 Compressors (7.38 MPa)	\$34,091,721.72			23
			CO2 Pumps (15 Mpa)	\$1,390,253.61			23
			CO2 Storage (0 hrs)	\$0.00			
			CO2 Pipeline (94 mi)	\$80,247,554.23		CO2 Pipeline Mileage 94 mi	23
			CO2 Injection (1 well)	\$2,453,365.73			23
			Costs of CO2 Disposal	\$118,182,895.30			
DepreciableCapital (Indirect)			(Component)				
			% of Uninstalled Costs	Site Preparation	1.2%		24
			% of Installed Costs	Engineering & Design	10%		24
			[\$]	Process Contingency	\$0.00		24
			% of Installed Costs	Project Contingency	25%		24
			[\$]	Other Depreciable Capital	\$0.00		24
			One-Time Licensing Fees	\$0.00			
			% of Uninstalled Costs	Up-Front Permitting Costs	15%		24
VarLinear	DepreciableCapital	[\$]	(CY)	2015	2050		24
Data				\$489,803,075.70	\$489,803,075.70		
VarData	LandRequired	[acres]		250			24
VarData	FixedOM		(Component)				
			FTEs	100			24
			Labor Costs	\$50.00			24
			Labor Costs	\$10,400,000.00			24
			Overhead and O&M	20%			
			Property Tax & Insurance	2%			24
			Rent	\$0.00			
			Lic. Permits and Fees	\$0.00			
			Matl for Maint. & Repairs	0.6%			24
			nt on CO2 Comp & Pumps	4.0%			23
			Maint on CO2 Pipelines	2.5%			23
			int on CO2 Injection Wells	\$108,540.30			23
			Other Fees	\$0.00			
			Other Fixed O&M Costs	\$0.00			
VarLinear	FixedOM	[\$/year]	(PY,CY)	2015	2050		
Data				\$27,317,349.96	\$27,317,349.96		
End				40	\$27,317,349.96		
VarLinear	OtherFixed	[\$/year]	(PY,CY)	2015	2050		
Data				\$0.00	\$0.00		
End				40	\$0.00		
VarLinear	FeedstockEfficiency		(Feedstock,CY)	2015	2050		
Data				0.0000	0.0000		
			Commercial Natural Gas	0.0000	0.0000		
			Industrial Natural Gas	0.0000	0.0000		
			Electric Utility Natural Gas	0.0000	0.0000		
			Commercial Electricity	0.0000	0.0000		
			Industrial Electricity	0.0000	0.0000		
			Jillity Steam Coal (Central)	0.6091	0.6091		24
			Diesel Fuel	0.0000	0.0000		
			Biomass	0.0000	0.0000		
			Ethanol	0.0000	0.0000		
			Methanol	0.0000	0.0000		
			Gasoline	0.0000	0.0000		
			Steam	0.0000	0.0000		
			Cooling Water	0.0000	0.0000		
			Deminerlized Water	0.0000	0.0000		
			Process Water	0.0101	0.0101		24
			Bio-oil	0.0000	0.0000		
			lity Steam Coal (Regional)	0.0000	0.0000		
			MSW (1)	0.0000	0.0000		
			MSW (2)	0.0000	0.0000		
End							
OtherVariableOM			(Component)				
			WT Costs	\$100,000.00			24
			SWD Costs	\$796,000.00			24
			Other Variable Op. Costs	\$1,029,000.00			
			Royalties	\$0.00			
			Operator Profit	\$0.00			
			Subsidies, Tax Incentives	\$0.00			
			Elect for CO2 Disposal	\$10,728,957.82			23
			CO2 Separation & Seq	\$0.00			24
VarLinear	OtherVariableOM	[\$/kgH2]	(PY,CY)	2015	2050		
Data				\$0.1218	\$0.1218		
End				40	\$0.1218		
VarLinear	ByproductEfficiency		(Byproduct,CY)	2015	2050		
Data				0.0000	0.0000		24
End				0.0000	0.0000		
VarLinear	Emissions	[kg/kgH2]	(Species,CY)	2015	2050		
Data				0	0		
			Carbon	0	0		
			GHG Equivalents	3,508,489,429	3,508,489,429		10
			NOX	0	0		
			SOX	0	0		
			Particulates (PM10)	0	0		
			Mercury	0	0		
End							
VarLinear	ReplacementCosts	[\$]	(PY,CY)	2015	2050		
Data				\$2,449,015.38	\$2,449,015.38		24
End				40	\$2,449,015.38		
VarLinear	LearningFactor		(Technology Factor)	2015	2050		
Data				\$2,449,015.38	\$2,449,015.38		
End				\$2,449,015.38	\$2,449,015.38		
VarData	InitialUnitNo	[unit # in CYBegin]		500			
VarData	LearningFactorStart			1			

0	Variable	[Units]	(y-axis,x-axis)	Data	Source Used
VarData	IClass			[1,1,1,12]	
VarData	OClass			[2,1,-1]	
VarData	CYStart	[Year]		2025	
VarData	CYStop	[Year]		2050	
Axis	CY	CY		[2025:2050]	
VarData	IRR	[%]		10%	
VarData	DepreciationLength	[Years]		20	
VarData	AnalysisPeriod	[Years]		20	
VarData	Life	[Years]		40	
Axis	PY	PY		[1:40]	
VarData	DesignCapacity	[kgH2/day]		246.478	
VarData	DesignCapacity	[kgH2/year]		89,964,470	
VarData	CapacityFactor	[% of DesignCapacity]		90%	
VarData	Location			-4	
DepreciableCapital (Direct)					
	(Component)		Uninstalled Costs	Installation Factor	Installed Costs
	Coal Handling Prep & Feed		\$22,881,589.63	153%	\$35,459,650.02
	Feedwater & Misc. BOP Systems		\$6,401,057.14	147%	\$9,412,307.14
	Gasifier & Accessories		\$50,541,901.49	138%	\$69,800,373.62
	Air Separation Unit		\$34,796,960.00	100%	\$34,796,960.00
	Hydrogen Separation & Gas Cleanup		\$53,972,240.00	100%	\$53,972,240.00
	Expander/Generators & SOFC/CT		\$58,342,062.94	118%	\$68,912,359.64
	HRSG & Steam Turbine Generator		\$12,353,779.71	122%	\$15,056,717.86
	Cooling Water System		\$1,582,749.31	148%	\$2,345,668.04
	Ash Handling System		\$4,636,589.63	141%	\$6,531,645.19
	Accessory Electric Plant		\$16,908,104.44	157%	\$26,603,207.94
	I&C		\$8,422,406.68	153%	\$12,917,180.06
	Buildings & Structures		\$3,254,656.75	194%	\$6,325,147.41
	Uninstalled Costs		\$274,084,097.73		
	Installed Costs		\$242,122,455.91		
	CO2 Compressors (7.38 MPa)		\$34,092,424.61		
	CO2 Pumps (15 Mpa)		\$1,390,321.91		
	CO2 Storage (0 hrs)		\$0.00		
	CO2 Pipeline (94 mi)		\$80,249,007.22		
	CO2 Injection (1 well)		\$2,453,371.83		
	Costs of CO2 Disposal		\$118,185,125.57		
	CO2 Pipeline Mileage		94 mi		
DepreciableCapital (Indirect)					
	(Component)				
	Site Preparation		1.0%		
	Engineering & Design		10%		
	Process Contingency		\$0.00		
	Project Contingency		25%		
	Other Depreciable Capital		\$0.00		
	One-Time Licensing Fees		\$0.00		
	Up-Front Permitting Costs		10%		
VarLinear	DepreciableCapital	[\$]		2025	2050
Data				\$610,199,693.15	\$610,199,693.15
VarData	LandRequired	[acres]		250	
FixedOM					
	(Component)				
	FTEs		120		
	Labor Costs		\$50.00		
	Labor Costs		\$12,480,000.00		
	Overhead and O&M		20%		
	Property Tax & Insurance		2%		
	Rent		\$0.00		
	Lic., Permits and Fees		\$0.00		
	Matl for Maint. & Repairs		0.6%		
	nt on CO2 Comp & Pumps		4.0%		
	Maint on CO2 Pipelines		2.5%		
	int on CO2 Injection Wells		\$ 108,542.20		
	Other Fees		\$0.00		
	Other Fixed O&M Costs		\$0.00		
VarLinear	FixedOM	[\$/year]		2025	2050
Data				\$32,766,805.85	\$32,766,805.85
End				\$32,766,805.85	\$32,766,805.85
VarLinear	OtherFixed	[\$/year]		2025	2050
Data				\$0.00	\$0.00
End				\$0.00	\$0.00
VarLinear	FeedstockEfficiency			2025	2050
Data				0.0000	0.0000
	(GJH2/GJFeedstock)			0.0000	0.0000
	Commercial Natural Gas			0.0000	0.0000
	Industrial Natural Gas			0.0000	0.0000
	Electric Utility Natural Gas			0.0000	0.0000
	Commercial Electricity			0.0000	0.0000
	Industrial Electricity			0.0000	0.0000
	Utility Steam Coal (Central)			0.4746	0.4746
	Diesel Fuel			0.0000	0.0000
	Biomass			0.0000	0.0000
	Ethanol			0.0000	0.0000
	Methanol			0.0000	0.0000
	Gasoline			0.0000	0.0000
	Steam			0.0000	0.0000
	Cooling Water			0.0000	0.0000
	Demineralized Water			0.0000	0.0000
	Process Water			0.0108	0.0108
	Bio-oil			0.0000	0.0000
	Utility Steam Coal (Regional)			0.0000	0.0000
	MSW (1)			0.0000	0.0000
	MSW (2)			0.0000	0.0000
OtherVariableOM					
	(Component)				
	WT Costs		\$100,000.00		
	SWD Costs		\$796,000.00		
	Other Variable Op. Costs		\$1,029,000.00		
	Royalties		\$0.00		
	Operator Profit		\$0.00		
	Subsidies, Tax Incentives		\$0.00		
	Elect for CO2 Disposal		\$10,729,512.86		
	CO2 Separation & Seq.		\$0.00		
VarLinear	OtherVariableOM	[\$/kgH2]		2025	2050
Data				\$0.1563	\$0.1563
End				\$0.1563	\$0.1563
VarLinear	ByproductEfficiency			2025	2050
Data				-2.2799	-2.2799
End				0.0000	0.0000
VarLinear	Emissions	[kg/kgH2]		2025	2050
Data				0	0
	Carbon			4.502446552	4.502446552
	GHG Equivalents			0	0
	NOX			0	0
	SOX			0	0
	Particulates (PM10)			0	0
	Mercury			0	0
ReplacementCosts					
	(PY,CY)			2025	2050
VarLinear				1	1
Data				\$3,050,998.47	\$3,050,998.47
End				\$3,050,998.47	\$3,050,998.47
VarLinear	LearningFactor			2025	2050
Data				1	5
End				2	1
VarData	InitialUnitNo	[unit # in CYbegin]		500	
VarData	LearningFactorStart			1	

Plant Description
Hot raw gas from the transport gasifier is sent to the hot gas desulfurization process for desulfurization. Elemental sulfur is produced as a byproduct. The clean filtered hot gas then goes through a hydrogen separation membrane where the shift reaction occurs and hydrogen is separated from CO2. A portion of the hydrogen is fired to heat compressed air entering the TMA oxygen separation unit. Heat for the air is also extracted from the hot CO2 stream with a high temperature heat exchanger. Additional hydrogen is used to produce power from a combined cycle SOFC. Pure oxygen produced from the TMA is cooled and compressed for use in the gasifier. The remaining hydrogen is compressed for product delivery. The CO2-rich stream is fired with oxygen and expanded to recover energy as power. The CO2 exhaust is compressed for pipeline delivery.

CO2 separation is addressed with this equipment.

See Rows 125+ for CCSD equations.

Site Prep & Permitting Costs are % of Uninstalled Costs. This deviates from Reference 24 & 25. We believe Reference is in error.

H2A has this as a % of Depreciable Capital + Land Costs. We do not multiply by Land Costs because Land Costs are computer in MATLAB.

40gpm @ \$2500/yr-gpm

79600 tonne/yr @ \$10/tonne

Shift catalyst: Amine: & PSA SO2 Catalyst Consumables

Set to zero. H2A costs for this are covered in other categories on this worksheet.

0.5% of DepreciableCapital

Each row corresponds to a technology sheet. Building one of the current sheet will decrease the cost of every technology listed by the corresponding "Factor." The numbers in the first three columns are the 1st, 2nd and 4th numbers of the technology-to-be-chapened's IClass var

All delivery (1-3) sheets with the same J share a LearningFactor (e.g., LT to 0.1TPD and LT to 1.5TPD only need one LearningFactor, since both sheets represent the same underlying technology - LTs). The L for this common factor should always be 1, and the factor should appear on every sheet that shares it.

Building an upper-bound FC ought to decrease the cost of a normal FC by the same amount. You would probably want a similar LearningFactor (maybe even a reference) on the normal FC-sheet

Variable	[Units]	(y-axis,x-axis)	Data	Source Used
Var/Data	IClass		[1,1,1,13]	
Var/Data	OClass		[2,2,-3]	
Var/Data	CYStart	[Year]	2015	
Var/Data	CYStop	[Year]	2050	24
Axis	CY	CY	[2015:2050]	
Var/Data	IRR	[%]	10%	24
Var/Data	DepreciationLength	[Years]	20	24
Var/Data	AnalysisPeriod	[Years]	20	
Var/Data	Life	[Years]	40	24
Axis	PY	PY	[1:40]	
Var/Data	DesignCapacity	[kgH2/day]	316.289	24
Var/Data	DesignCapacity	[kgH2/year]	115,445,485	
Var/Data	CapacityFactor	[% of DesignCapacity]	90%	24
Var/Data	Location		4	
DepreciableCapital (Direct)				
	(Component)	Uninstalled Costs	Installation Factor	Installed Costs
	Coal Handling Prep & Feed	\$20,030,413.64	155%	\$31,041,176.28
	Feedwater & Misc. BOP Systems	\$2,643,325.71	147%	\$3,886,825.71
	Gasifier & Accessories	\$61,000,733.91	138%	\$84,244,436.65
	Air Separation Unit	\$34,786,960.00	100%	\$34,786,960.00
	Hydrogen Separation & Gas Cleanup	\$48,851,040.00	100%	\$48,851,040.00
	HRSG Ducting & Stack	\$0.00	118%	\$0.00
	Steam Turbine Generator	\$9,462,427.63	122%	\$11,531,988.10
	Cooling Water System	\$4,297,840.00	148%	\$6,369,490.00
	Ash Handling System	\$5,690,360.00	141%	\$8,016,110.00
	Accessory Electric Plant	\$3,715,213.82	157%	\$5,845,516.63
	I&C	\$6,955,160.00	153%	\$10,666,910.00
	Buildings & Structures	\$3,073,418.88	194%	\$5,972,927.09
	Other	\$0.00		\$0.00
	Uninstalled Costs	\$200,506,893.60		
	Installed Costs	\$251,213,380.47		
	CO2 Compressors (7.38 MPa)	\$36,530,671.78		
	CO2 Pumps (15 Mpa)	\$1,640,187.16		
	CO2 Storage (0 hrs)	\$0.00		
	CO2 Pipeline (94 mi)	\$85,267,734.67	CO2 Pipeline Mileage	94 mi
	CO2 Injection (1 well)	\$2,474,720.33		
	Costs of CO2 Disposal	\$125,913,313.95		
DepreciableCapital (Indirect)				
	(Component)			
	% of Uninstalled Costs	1.2%		24
	% of Installed Costs	10%		24
	Site Preparation	\$0.00		
	Engineering & Design	\$0.00		
	Process Contingency	25%		24
	Project Contingency	\$0.00		
	Other Depreciable Capital	\$0.00		
	One-Time Licensing Fees	\$0.00		
	% of Uninstalled Costs	15%		24
	Up-Front Permitting Costs	2015 2050		24
Var/Linear	DepreciableCapital	[\$]	\$497,533,494.34 \$497,533,494.34	Site Prep & Permitting Costs are % of Uninstalled Costs. This deviates from Reference 24 & 25. We believe Reference is in error.
Data				
Var/Data	LandRequired	[acres]	250	24
Var/Data	FixedOM			
	(Component)			
	FTEs	100		24
	Labor Costs	\$50.00		24
	Labor Costs	\$10,400,000.00		
	Overhead and O&M	20%		24
	Property Tax & Insurance	2%		24
	Rent	\$0.00		
	Lic. Permits and Fees	\$0.00		
	Maint for Maint. & Repairs	0.6%		24
	Maint on CO2 Comp & Pumps	4.0%		23
	Maint on CO2 Pipelines	2.5%		23
	Maint on CO2 Injection Wells	\$ 115,201.59		23
	Other Fees	\$0.00		
	Other Fixed O&M Costs	\$0.00		
Var/Linear	FixedOM	[\$/year]	2015 2050	
Data				
End				
Var/Linear	OtherFixed	[\$/year]	2015 2050	
Data				
End				
Var/Linear	FeedstockEfficiency		2015 2050	
Data		(Feedstock,CY)		
	(GJ,H2/GJfeedstock)	Commercial Natural Gas	0.0000 0.0000	
	(GJ,H2/GJfeedstock)	Industrial Natural Gas	0.0000 0.0000	
	(GJ,H2/GJfeedstock)	Electric Utility Natural Gas	0.0000 0.0000	
	(GJ,H2/GJ)	Commercial Electricity	0.0000 0.0000	
	(GJ,H2/GJ)	Industrial Electricity	0.0000 0.0000	
	(GJ,H2/GJfeedstock)	Utility Steam Coal (Central)	0.6091 0.6091	24
	(GJ,H2/GJfeedstock)	Diesel Fuel	0.0000 0.0000	
	(GJ,H2/GJfeedstock)	Biomass	0.0000 0.0000	
	(GJ,H2/GJfeedstock)	Ethanol	0.0000 0.0000	
	(GJ,H2/GJfeedstock)	Methanol	0.0000 0.0000	
	(GJ,H2/GJfeedstock)	Gasoline	0.0000 0.0000	
	(GJ,H2/GJfeedstock)	Steam	0.0000 0.0000	
	(GJ,H2/L)	Cooling Water	0.0000 0.0000	
	(GJ,H2/L)	Deminerlized Water	0.0000 0.0000	
	(GJ,H2/L)	Process Water	0.0101 0.0101	24
	(GJ,H2/Barrel)	Bio-oil	0.0000 0.0000	
	(GJ,H2/GJfeedstock)	Utility Steam Coal (Regional)	0.0000 0.0000	
	(GJ,H2/GJfeedstock)	MSW (1)	0.0000 0.0000	
	(GJ,H2/GJfeedstock)	MSW (2)	0.0000 0.0000	
End	OtherVariableOM			
	(Component)			
	WT Costs	\$100,000.00		24
	SWD Costs	\$796,000.00		24
	Other Variable Op. Costs	\$1,029,000.00		24
	Royalties	\$0.00		
	Operator Profit	\$0.00		
	Subsidies, Tax Incentives	\$0.00		
	Elect for CO2 Disposal	\$12,760,027.06		23
	CO2 Separation & Seq	\$6,750,000.00		24
Var/Linear	OtherVariableOM	[\$/kgH2]	2015 2050	
Data				
End				
Var/Linear	ByproductEfficiency		2015 2050	
Data		(Byproduct,CY)		
End				
Var/Linear	Emissions	[kg/kgH2]	2015 2050	
Data		(Species,CY)		
		Carbon	0 0	19
		GHG Equivalents	0 0	
		NOX	0 0	
		SOX	0 0	
		Particulates (PM10)	0 0	
		Mercury	0 0	
End	ReplacementCosts	[\$]	2015 2050	
Data				
End				
Var	LearningFactor			
Data		(Technology Factor)		
End		FC,NG-SMR,1.5 (UPPER)	1 5 2	
Var/Data	InitialUnitNo	[unit # in CYBegin]	500	
Var/Data	LearningFactorStart		1	

Plant Description

Hot raw gas from the I-Gas gasifier is cooled and sent to the SCOH5 process for desulfurization. Elemental sulfur is produced as a byproduct. The clean gas is filtered goes through a hydrogen separation membrane where the surface shift reaction occurs and hydrogen is separated from CO2. A portion of the hydrogen is fired to heat compressed air entering the ITM oxygen separation unit. Pure oxygen produced from the ITM is cooled and compressed for use in the gasifier. The remaining hydrogen is compressed for product delivery. The CO2-rich stream is fired with oxygen and expanded to recover energy as power. The CO2 exhaust is compressed for pipeline delivery.

See Rows 125+ for CCSD equations.

Site Prep & Permitting Costs are % of Uninstalled Costs. This deviates from Reference 24 & 25. We believe Reference is in error.

H2A has this as a % of Depreciable Capital - LandCosts. We do not multiply by Land Costs because Land Costs are computer in MATLAB.

40gpm @ \$2500/yr-gpm

79600 tonne/yr @ \$10/tonne

Shift catalyst: Amine: & PSA, SO2 Catalyst Consumables.

Julie_perez: 1,650,000 tonne CO2/year: Basis \$15/tonne CO2 for sequestration: 90% CO2 Recovery.

0.5% of DepreciableCapital

Each row corresponds to a technology sheet. Building one of the current sheet will decrease the cost of every technology listed by the corresponding "Factor". The numbers in the first three columns are the 1st, 2nd and 4th numbers of the technology to be cheapened's IClass var

All delivery (1-3) sheets with the same J share a Learningfactor (e.g. LT to 0.11PD and LT to 1.51PD only need one Learningfactor, since both sheets represent the same underlying technology - LTs). The L for this common factor should always be 1, and the factor should appear on every sheet that shares it.

Building an upper-bound FC ought to decrease the cost of a normal FC by the same amount. You would probably want a similar Learningfactor (maybe even a reference) on the normal FC sheet.

-1	Variable	[Units]	(y-axis,x-axis)	Data	Source Used
VarData	IClass			[1,2,1,1]	
VarData	OClass			[2,1,-1]	
VarData	CIStart	[Year]		2005	25
VarData	CYStop	[Year]		2050	
Axis	CY	CY		[2005-2050]	
VarData	IRR	[%]		10%	18
VarData	DepreciationLength	[Years]		20	25
VarData	AnalysisPeriod	[Years]		20	
VarData	Life	[Years]		40	25
Axis	PY	PY		[1-40]	
VarData	DesignCapacity	[kgH2/day]		15,000	25
VarData	DesignCapacity	[kgH2/year]		5,475,000	
VarData	CapacityFactor	[% of DesignCapacity]		90%	25
VarData	Location			2	
	DepreciableCapital (Direct)		(Component)		
			Uninstalled Costs	\$26,556,000.00	25
			Installed Costs	\$51,519,000.00	25
	DepreciableCapital (Indirect)		(Component)		
		[% of Installed Costs]	Project Contingency	10%	25
		[% of Installed Costs]	Other Depreciable Capital	27%	25
VarLinear	DepreciableCapital	[\$]			
Data			(CY)	2005 2050	
VarData	LandRequired	[acres]		25	26
VarData	FixedOM	[\$/year]	(PY,CY)	2005 2050	
Data			1	\$0.00 \$0.00	25
End			40	\$0.00 \$0.00	
VarLinear	OtherFixed	[\$/year]	(PY,CY)	2005 2050	
Data			1	\$0.00 \$0.00	25
End			40	\$0.00 \$0.00	
VarLinear	FeedstockEfficiency		(Feedstock,CY)	2005 2050	
Data					
	[GJH2/GJFeedstock]		Commercial Natural Gas	0.0000 0.0000	
	[GJH2/GJFeedstock]		Industrial Natural Gas	0.0000 0.0000	
	[GJH2/GJFeedstock]		Electric Utility Natural Gas	0.0000 0.0000	
	[GJH2/GJ]		Commercial Electricity	0.0000 0.0000	
	[GJH2/GJ]		Industrial Electricity	0.0000 0.0000	
	[GJH2/GJFeedstock]		Jillby Steam Coal (Central)	0.5350 0.5350	25
	[GJH2/GJFeedstock]		Diesel Fuel	0.0000 0.0000	
	[GJH2/GJFeedstock]		Biomass	0.0000 0.0000	
	[GJH2/GJFeedstock]		Ethanol	0.0000 0.0000	
	[GJH2/GJFeedstock]		Methanol	0.0000 0.0000	
	[GJH2/GJFeedstock]		Gasoline	0.0000 0.0000	
	[GJH2/GJFeedstock]		Steam	0.0000 0.0000	
	[GJH2/L]		Cooling Water	0.0000 0.0000	
	[GJH2/L]		Deminerlized Water	0.0000 0.0000	
	[GJH2/L]		Process Water	0.0108 0.0108	18
	[GJH2/Barel]		Bio-oil	0.0000 0.0000	
	[GJH2/GJFeedstock]		Illy Steam Coal (Regional)	0.0000 0.0000	
	[GJH2/GJFeedstock]		MSW (1)	0.0000 0.0000	
	[GJH2/GJFeedstock]		MSW (2)	0.0000 0.0000	
End					
VarLinear	OtherVariableOM	[\$/kgH2]	(PY,CY)	2005	
Data			1	0.0360 0.0360	25
End			40	0.0360 0.0360	
VarLinear	ByproductEfficiency		(Byproduct,CY)	2005 2050	
Data					
	[GJH2/GJ]		Byproduct Electricity	-11.5358 -11.5358	25
End					
VarLinear	Emissions	[kg/kgH2]	(Species,CY)	2005 2050	
Data					
			Carbon	0 0	
			GHG Equivalents	23.09240066 23.09240066	19
			NOX	0.006 0.006	25
			SOX	0 0	
			Particulates (PM10)	0 0	
			Mercury	0 0	
End					
VarLinear	ReplacementCosts	[\$]	(PY,CY)	2005 2050	
Data			1	\$352,280.15 \$352,280.15	18
End			40	\$352,280.15 \$352,280.15	
Var	LearningFactor		(Technology,Factor)	IClass[1] (I)	
Data					
			FC,NG-SMR,1.5 (UPPER)	1 5 3	
End					
VarData	InitialUnitNo	[unit # in CYBegin]		500	
VarData	LearningFactorStart			1	

Plant Description

A City Gate hydrogen plant fed with Pittsburgh No. 8 bituminous coal based on the ConocoPhillips E-Gas process. This coal is characterized having high volatility, low ash and moisture content, and high as-received heating value. The pressurized entrained flow E-GAS™ two-stage gasifier uses a coal/water slurry and oxygen to produce a medium heating value fuel gas. The syngas produced in the gasifier first stage at about 1343°C (2450°F) is quenched to 1038°C (1900°F) by reacting with slurry injected into the second stage. Gas leaving the gasifier is cooled in a fire-tube syngas cooler producing high pressure steam. The cooled gas is cleaned of particulate via a cyclone collector followed by a ceramic candle filter. After leaving the particulate control unit, steam is injected into the gas stream and the CO in the syngas is shifted to hydrogen and CO₂ in the shift converter utilizing a sulfur-tolerant shift catalyst. The gas stream is sent to the sulfur removal unit which removes H₂S and some of the CO₂. The clean gas stream then passes through the PSA for final purification of the hydrogen. Regeneration gas from the PSA contains fuel value, and is fed to the HRSG for duct-firing. Regeneration gas from the AGR plant is fed to a sulfuric acid plant.

Ruffkowski has this as a % of Installed Costs + LandCosts (we account for this in the formula for DepreciableCapital).

0.5% of DepreciableCapital

Each row corresponds to a technology sheet. Building one of the current sheet will decrease the cost of every technology listed by the corresponding "Factor". The numbers in the first three columns are the 1st, 2nd and 4th numbers of the technology to-be cheapened's IClass var

All delivery (I=3) sheets with the same J share a LearningFactor (e.g., LT to 0.1TPO and LT to 1.5TPO only need one LearningFactor since both sheets represent the same underlying technology - LTs). The L for this common factor should always be 1, and the factor should appear on every sheet that shares it.

Building an upper-bound FC ought to decrease the cost of a normal FC by the same amount. You would probably want a similar LearningFactor (maybe even a reference) on the normal FC sheet

-1	Variable	[Units]	(y-axis,x-axis)	Data	Source Used
VarData	IClass			[1,2,1,2]	
VarData	OClass			[2,1,-1]	
VarData	CYStart	[Year]		2015	25
VarData	CYStop	[Year]		2050	
Axis	CY	CY		[2015:2050]	
VarData	IRR	[%]		10%	20
VarData	DepreciationLength	[Years]		20	25
VarData	AnalysisPeriod	[Years]		20	
VarData	Life	[Years]		40	25
Axis	PY	PY		[1:40]	
VarData	DesignCapacity	[kgH2/day]		15,000	25
VarData	DesignCapacity	[kgH2/year]		5,475,000	
VarData	CapacityFactor	[% of DesignCapacity]		90%	25
VarData	Location			2	
DepreciableCapital (Direct)			(Component)		
			Uninstalled Costs	\$32,729,000.00	25
			Installed Costs	\$41,489,000.00	25
DepreciableCapital (Indirect)			(Component)		
			Project Contingency	10%	25
			% of Installed Costs		25
VarLinear	DepreciableCapital	[\$]	Other Depreciable Capital	27%	25
Data			(CY)	2015 2050	
VarData	LandRequired	[acres]		\$56,714,930.00 \$56,714,930.00	
VarLinear	FixedOM	[\$/year]	(PY,CY)	2015 2050	26
Data			1	\$926,862.75 \$926,862.75	
End			40	\$926,862.75 \$926,862.75	25
VarLinear	OtherFixed	[\$/year]	(PY,CY)	2015 2050	
Data			1	\$0.00 \$0.00	
End			40	\$0.00 \$0.00	25
VarLinear	FeedstockEfficiency		(Feedstock,CY)	2015 2050	
Data					
	[GJH2/GJFeedstock]		Commercial Natural Gas	0.0000 0.0000	
	[GJH2/GJFeedstock]		Industrial Natural Gas	0.0000 0.0000	
	[GJH2/GJFeedstock]		Electric Utility Natural Gas	0.0000 0.0000	
	[GJH2/GJ]		Commercial Electricity	0.0000 0.0000	
	[GJH2/GJ]		Industrial Electricity	0.0000 0.0000	
	[GJH2/GJFeedstock]		Jillby Steam Coal (Central)	0.5499 0.5499	25
	[GJH2/GJFeedstock]		Diesel Fuel	0.0000 0.0000	
	[GJH2/GJFeedstock]		Biomass	0.0000 0.0000	
	[GJH2/GJFeedstock]		Ethanol	0.0000 0.0000	
	[GJH2/GJFeedstock]		Methanol	0.0000 0.0000	
	[GJH2/GJFeedstock]		Gasoline	0.0000 0.0000	
	[GJH2/GJFeedstock]		Steam	0.0000 0.0000	
	[GJH2/L]		Cooling Water	0.0000 0.0000	
	[GJH2/L]		Deminerlized Water	0.0000 0.0000	
	[GJH2/L]		Process Water	0.0101 0.0101	
	[GJH2/Barrel]		Bio-oil	0.0000 0.0000	18
	[GJH2/GJFeedstock]		Jillby Steam Coal (Regional)	0.0000 0.0000	
	[GJH2/GJFeedstock]		MSW (1)	0.0000 0.0000	
	[GJH2/GJFeedstock]		MSW (2)	0.0000 0.0000	
End					
VarLinear	OtherVariableOM	[\$/kgH2]	(PY,CY)	2015	
Data			1	0.0185 0.0185	25
End			40	0.0185 0.0185	
VarLinear	ByproductEfficiency		(Byproduct,CY)	2015 2050	
Data					
	[GJH2/GJ]		Byproduct Electricity	0.0000 0.0000	
End			Steam	0.0000 0.0000	25
VarLinear	Emissions	[kg/kgH2]	(Species,CY)	2015 2050	
Data					
			Carbon	0 0	
			GHG Equivalents	22.47002183 22.47002183	
			NOX	0 0	19
			SOX	0 0	
			Particulates (PM10)	0 0	
			Mercury	0 0	
End					
VarLinear	ReplacementCosts	[\$]	(PY,CY)	2015 2050	
Data			1	\$283,574.65 \$283,574.65	18
End			40	\$283,574.65 \$283,574.65	
Var	LearningFactor		(Technology,Factor)	IClass[1] (I) ICClass[2] (I) ICClass[4] (L) Factor	
Data			FC,NG-SMR,1.5 (UPPER)	1 5 3	
End			FC,NG-SMR,1.5	1 5 2 1	
VarData	InitialUnitNo	[unit # in CYBegin]		500	
VarData	LearningFactorStart			1	

Plant Description
The 2015 plant is based on an E-Gas gasifier but utilizes an ITM membrane for oxygen production, a Selective Oxidation of H2S (SOHS) process, and a hydrogen separation membrane. CO2 recovery is inherent.

Rutkowski has this as a % of Installed Costs+LandCosts (see account for this in the formula for DepreciableCapital).

Each row corresponds to a technology sheet. Building one of the current sheet will decrease the cost of every technology listed by the corresponding "Factor". The numbers in the first three columns are the 1st, 2nd and 4th numbers of the technology to-be-cheapened's IClass var

All delivery (1-3) sheets with the same J share a Learningfactor (e.g., LT to 0.1TPD and LT to 1.5TPD only need one Learningfactor, since both sheets represent the same underlying technology - LTS). The L for this common factor should always be 1, and the factor should appear on every sheet that shares it.

Building an upper-bound FC ought to decrease the cost of a normal FC by the same amount. You would probably want a similar Learningfactor (maybe even a reference) on the normal FC sheet

-1	Variable	[Units]	(y-axis,x-axis)	Data	Source Used
VarData	IClass			[1,2,1,3]	
VarData	OClass			[2,1,-1]	
VarData	CYStart	[Year]		2030	25
VarData	CYStop	[Year]		2050	
Axis	CY	CY		[2030:2050]	
VarData	IRR	[%]		10%	20
VarData	DepreciationLength	[Years]		20	25
VarData	AnalysisPeriod	[Years]		20	
VarData	Life	[Years]		40	25
Axis	PY	PY		[1:40]	
VarData	DesignCapacity	[kgH2/day]		15,000	25
VarData	DesignCapacity	[kgH2/year]		5,475,000	
VarData	CapacityFactor	[% of DesignCapacity]		90%	25
VarData	Location			2	
	DepreciableCapital (Direct)		(Component)		
			Uninstalled Costs	\$44,739,000.00	25
			Installed Costs	\$55,845,000.00	25
	DepreciableCapital (Indirect)		(Component)		
			Project Contingency	10%	25
			% of Installed Costs		25
VarLinear	DepreciableCapital	[\$]	Other Depreciable Capital	27%	25
Data			(CY)	2030 2050	
VarData	LandRequired	[acres]		25	26
VarLinear	FixedOM	[\$/year]	(PY,CY)	2030 2050	
Data			1	\$1,527,032.25 \$1,527,032.25	25
End			40	\$1,527,032.25 \$1,527,032.25	
VarLinear	OtherFixed	[\$/year]	(PY,CY)	2030 2050	
Data			1	\$0.00 \$0.00	25
End			40	\$0.00 \$0.00	
VarLinear	FeedstockEfficiency		(Feedstock,CY)	2030 2050	
Data					
		[GJH2/GJFeedstock]	Commercial Natural Gas	0.0000 0.0000	
		[GJH2/GJFeedstock]	Industrial Natural Gas	0.0000 0.0000	
		[GJH2/GJFeedstock]	Electric Utility Natural Gas	0.0000 0.0000	
		[GJH2/GJ]	Commercial Electricity	0.0000 0.0000	
		[GJH2/GJ]	Industrial Electricity	0.0000 0.0000	
		[GJH2/GJFeedstock]	Jillby Steam Coal (Central)	0.4285 0.4285	25
		[GJH2/GJFeedstock]	Diesel Fuel	0.0000 0.0000	
		[GJH2/GJFeedstock]	Biomass	0.0000 0.0000	
		[GJH2/GJFeedstock]	Ethanol	0.0000 0.0000	
		[GJH2/GJFeedstock]	Methanol	0.0000 0.0000	
		[GJH2/GJFeedstock]	Gasoline	0.0000 0.0000	
		[GJH2/GJFeedstock]	Steam	0.0000 0.0000	
		[GJH2/L]	Cooling Water	0.0000 0.0000	
		[GJH2/L]	Deminerlized Water	0.0000 0.0000	
		[GJH2/L]	Process Water	0.0108 0.0108	18
		[GJH2/Barrrel]	Bio-oil	0.0000 0.0000	
		[GJH2/GJFeedstock]	Jillby Steam Coal (Regional)	0.0000 0.0000	
		[GJH2/GJFeedstock]	MSW (1)	0.0000 0.0000	
		[GJH2/GJFeedstock]	MSW (2)	0.0000 0.0000	
End					
VarLinear	OtherVariableOM	[\$/kgH2]	(PY,CY)	2030 2050	
Data			1	0.0238 0.0238	25
End			40	0.0238 0.0238	
VarLinear	ByproductEfficiency		(Byproduct,CY)	2030 2050	
Data					
		[GJH2/GJ]	Byproduct Electricity	-2.2870 -2.2870	25
End					
VarLinear	Emissions	[kg/kgH2]	(Species,CY)	2030 2050	
Data					
			Carbon	0 0	19
			GHG Equivalents	28.83330882 28.83330882	
			NOX	0 0	
			SOX	0 0	
			Particulates (PM10)	0 0	
			Mercury	0 0	
End					
VarLinear	ReplacementCosts	[\$]	(PY,CY)	2030 2050	
Data			1	\$381,913.25 \$381,913.25	18
End			40	\$381,913.25 \$381,913.25	
Var	LearningFactor		(Technology,Factor)	IClass[1] (I) IClass[2] (I) IClass[4] (L) Factor	
Data			FC,NG-SMR,1.5 (UPPER)	1 5 3 1	
End			FC,NG-SMR,1.5	1 5 2 1	
VarData	InitialUnitNo	[unit # in CYBegin]		500	
VarData	LearningFactorStart			1	

Plant Description
The 2030 plant is based on an advanced gasifier and more technology developments.

Rutkowski has this as a % of Installed Costs + LandCosts (we account for this in the formula for DepreciableCapital)

Each row corresponds to a technology sheet. Building one of the current sheet will decrease the cost of every technology listed by the corresponding "Factor". The numbers in the first three columns are the 1st, 2nd and 4th numbers of the technology to-be-cheapened's IClass var

All delivery (I=3) sheets with the same J share a LearningFactor (e.g., LT to 0.1TPD and LT to 1.5TPD only need one LearningFactor, since both sheets represent the same underlying technology - LTs). The L for this common factor should always be 1, and the factor should appear on every sheet that shares it

Building an upper-bound FC ought to decrease the cost of a normal FC by the same amount. You would probably want a similar LearningFactor (maybe even a reference) on the normal FC sheet

0	Variable	[Units]	(y-axis,x-axis)	Data	Source Used
VarData	IClass			[1,4,1,1]	
VarData	OClass			[2,1,-1]	
VarData	CYStart	[Year]		2005	25
VarData	CYStop	[Year]		2050	
Axis	CY	CY		[2005-2050]	
VarData	IRR	[%]		10%	20
VarData	DepreciationLength	[Years]		20	25
VarData	AnalysisPeriod	[Years]		20	
VarData	Life	[Years]		40	25
Axis	PY	PY		[1-40]	
VarData	DesignCapacity	[kgH2/day]		15,000	25
VarData	DesignCapacity	[kgH2/year]		5,475,000	
VarData	CapacityFactor	[% of DesignCapacity]		90%	25
VarData	Location			2	
	DepreciableCapital (Direct)		(Component,CY)	2005 2015	
			Uninstalled Costs	\$6,969,000.00 \$5,227,000.00	25
			Installed Costs	\$13,380,000.00 \$10,036,000.00	25
	DepreciableCapital (Indirect)		(Component)		
		[% of Installed Costs]	Project Contingency	10%	25
VarLinear	DepreciableCapital	[% of Installed Costs]	Other Depreciable Capital	27%	25
Data		(\$)	(CY)	2005 2015 2050	
VarData	LandRequired	[acres]		10	5
VarLinear	FixedOM	[\$/year]	(PY,CY)	2005 2015 2050	
Data			1	\$389,765.25 \$292,200.75 \$292,200.75	25
End			40	\$389,765.25 \$292,200.75 \$292,200.75	
VarLinear	OtherFixed	[\$/year]	(PY,CY)	2005 2050	
Data			1	\$0.00 \$0.00	25
End			40	\$0.00 \$0.00	
VarLinear	FeedstockEfficiency		(Feedstock,CY)	2005 2015 2025 2050	
Data		[GJH2/GJFeedstock]			
			Commercial Natural Gas	0.0000 0.0000 0.0000 0.0000	
			Industrial Natural Gas	0.7700 0.7900 0.8200 0.8666	5
			Electric Utility Natural Gas	0.0000 0.0000 0.0000 0.0000	
			Commercial Electricity	0.0000 0.0000 0.0000 0.0000	
			Industrial Electricity	25.9556 25.9556 25.9556 25.9556	FC 2015/2030
			Jubilee Steam Coal (Central)	0.0000 0.0000 0.0000 0.0000	
			Diesel Fuel	0.0000 0.0000 0.0000 0.0000	
			Biomass	0.0000 0.0000 0.0000 0.0000	
			Ethanol	0.0000 0.0000 0.0000 0.0000	
			Methanol	0.0000 0.0000 0.0000 0.0000	
			Gasoline	0.0000 0.0000 0.0000 0.0000	
			Steam	0.0000 0.0000 0.0000 0.0000	
			Cooling Water	0.0215 0.0215 0.0215 0.0215	27
			Deminerlized Water	0.0000 0.0000 0.0000 0.0000	
			Process Water	0.0027 0.0027 0.0027 0.0027	
			Bio-oil	0.0000 0.0000 0.0000 0.0000	31
			Illy Steam Coal (Regional)	0.0000 0.0000 0.0000 0.0000	
			MSW (1)	0.0000 0.0000 0.0000 0.0000	
			MSW (2)	0.0000 0.0000 0.0000 0.0000	
End					
VarLinear	OtherVariableOM	[\$/kgH2]	(PY,CY)	2005 2050	
Data			1	\$0.1716 \$0.1287 \$0.1287	25
End			40	\$0.1716 \$0.1287 \$0.1287	
VarLinear	ByproductEfficiency		(Byproduct,CY)	2005 2050	
Data		[GJH2/GJ]			
End			Byproduct Electricity	0.0000 0.0000	25
VarLinear	Emissions	[kg/kgH2]	(Species,CY)	2005 2015 2025 2050	
Data					
			Carbon	0 0 0 0	19
			GHG Equivalents	9.84 9.59 9.23907439 9.23907439	19
			NOX	0 0 0 0	25
			SOX	0 0 0 0	
			Particulates (PM10)	0 0 0 0	
			Mercury	0 0 0 0	
End					
VarLinear	ReplacementCosts	(\$)	(PY,CY)	2005 2015 2050	
Data			1	\$91,403.00 \$68,496.60 \$68,496.60	18
End			40	\$91,403.00 \$68,496.60 \$68,496.60	
Var	LearningFactor		(Technology, Factor)	IClass[1] (I) IClass[2] (J) IClass[4] (L) Factor	
Data			FC,NG-SMR,1.5 (UPPER)	1 5 3	
End			FC,NG-SMR,1.5	1 5 2 1	
VarData	InitialUnitNo	[unit # in CYBegin]		500	
VarData	LearningFactorStart			1	

Plant Description

This system involves a catalytic conversion of the hydrocarbon and steam to hydrogen and carbon oxides. The process consists of three main steps: (1) natural gas reformer/boiler, (2) water gas shift reaction and (3) gas purification. Natural gas is fed to the plant from the pipeline at a pressure of 3.10 MPa. To protect the catalysts in the hydrogen plant, the natural gas has to be desulfurized with a zinc oxide polishing bed before being fed to the reformer. After the reformer, the process gas mixture of CO₂, CO and H₂ passes through a heat recovery step and is fed into a water gas shift reactor to produce additional H₂. Treated gas from the shift reactor is fed directly to the Pressure Swing Adsorption (PSA) process is used for hydrogen purification where hydrogen is purified up to approximately 99.6%. Carbon oxides are limited to 10 ppm in the final hydrogen product.

Rutkowski has this as a % of Installed Costs+LandCosts (see account for this in the formula for DepreciableCapital)

Inferred value taken by dividing the central plant size in half.

Consensus of data from H2A, ACPH, H2Gen and Halidor Topsoe

Each row corresponds to a technology sheet. Building one of the current sheet will decrease the cost of every technology listed by the corresponding "Factor." The numbers in the first three columns are the 1st, 2nd and 4th numbers of the technology to be cheapened's IClass var

All delivery (1-3) sheets with the same J share a LearningFactor (e.g., LT to 0.11PD and LT to 1.5TPD only need one LearningFactor, since both sheets represent the same underlying technology [15]. The L for this common factor should always be 1, and the factor should appear on every sheet that shares it.

Building an upper-bound FC ought to decrease the cost of a normal FC by the same amount. You would probably want a similar LearningFactor (maybe even a reference) on the normal FC sheet

0	Variable	[Units]	(y-axis,x-axis)	Data		Source Used
VarData	IClass			{1,3,1,1}		
VarData	OClass			{2,1,-1}		
VarData	CYStart	[Year]		2005		27
VarData	CYStop	[Year]		2050		
Axis	CY	CY		{2005,2050}		
VarData	IRR	[%]		10%		27
VarData	DepreciationLength	[Years]		20		27
VarData	AnalysisPeriod	[Years]		20		
VarData	Life	[Years]		40		27
Axis	PY	PY		{1,40}		
VarData	DesignCapacity	[kgH2/day]		379.387		27
VarData	DesignCapacity	[kgH2/year]		138,476.250		
VarData	CapacityFactor	[% of DesignCapacity]		90%		27
VarData	Location			1		
	DepreciableCapital (Direct)	(Component)		Uninstalled Costs	Installation Factor	Installed Costs
		Process Plant Equipment (Reformer)		\$49,969,787.88	192%	\$96,064,561.05
		BOP and Offsites		\$19,964,650.75	192%	\$38,381,099.71
		SCR NOx Control on Stack		\$296,650.72	192%	\$570,454.55
	DepreciableCapital (Direct)	(Component,CY)		2005	2015	
		Cost Factor		100%	72%	
		Uninstalled Costs		\$70,231,089.35	\$52,673,317.01	28
		Installed Costs		\$135,016,115.30	\$101,262,086.48	
	DepreciableCapital (Indirect)	(Component)				
		Site Preparation		2.0%		27
		Engineering & Design		10%		27
		Process Contingency		\$0.00		
		Project Contingency		15%		27
		Other Depreciable Capital		\$0.00		
		One-Time Licensing Fees		\$0.00		
		Up-Front Permitting Costs		15%		27
VarLinear	DepreciableCapital	[\$]	(CY)	2005	2015	2050
Data				\$180,709,429.32	\$135,532,071.99	\$135,532,071.99
VarData	LandRequired	[acres]		20		5
VarData	FixedOM	(Component,CY)		2005	2015	
		FTEs		20	20	
		Hours/year				
		Labor Costs		\$50.00	\$50.00	
		Labor Costs		\$2,080,000.00	\$2,080,000.00	
		Overhead and G&A		20%	20%	
		Property Tax & Insurance		2%	2%	
		Rent		\$0.00	\$0.00	
		Lic., Permits and Fees		\$0.00	\$0.00	
		M&I for Maint. & Repairs		0.6%	0.6%	
		Other Fees		\$0.00	\$0.00	
		Other Fixed O&M Costs		\$0.00	\$0.00	
VarLinear	FixedOM	[\$/year]	(PY,CY)	2005	2015	2050
Data				1	\$6,920,285.28	\$5,814,213.96
End				40	\$6,920,285.28	\$5,814,213.96
VarLinear	OtherFixed	[\$/year]	(PY,CY)	2005	2050	
Data				1	\$0.00	\$0.00
End				40	\$0.00	\$0.00
VarLinear	FeedstockEfficiency	(Feedstock,CY)		2005	2015	2025
Data				2050		
End				2050		
		Commercial Natural Gas		0.0000	0.0000	0.0000
		Industrial Natural Gas		0.8400	0.8500	0.8700
		Electric Utility Natural Gas		0.0000	0.0000	0.0000
		Commercial Electricity		0.0000	0.0000	0.0000
		Industrial Electricity		59.3010	59.3010	59.3010
		Jelly Steam Coal (Central)		0.0000	0.0000	0.0000
		Diesel Fuel		0.0000	0.0000	0.0000
		Biomass		0.0000	0.0000	0.0000
		Ethanol		0.0000	0.0000	0.0000
		Methanol		0.0000	0.0000	0.0000
		Gasoline		0.0000	0.0000	0.0000
		Steam		0.0000	0.0000	0.0000
		Cooling Water		0.0215	0.0215	0.0215
		Demineralized Water		0.0096	0.0096	0.0096
		Process Water		0.0000	0.0000	0.0000
		Bio-oil		0.0000	0.0000	0.0000
		lity Steam Coal (Regional)		0.0000	0.0000	0.0000
		MSW (1)		0.0000	0.0000	0.0000
		MSW (2)		0.0000	0.0000	0.0000
	OtherVariableOM	(Component,CY)		2005	2015	
		WT Costs		\$0.00	\$0.00	
		SWD Costs		\$0.00	\$0.00	
		Other Variable Op. Costs		\$2,123,000.00	\$2,123,000.00	
		Royalties		\$0.00	\$0.00	
		Operator Profit		\$0.00	\$0.00	
		Subsidies, Tax Incentives		\$0.00	\$0.00	
		CO2 Separation & Seq		\$0.00	\$0.00	
VarLinear	OtherVariableOM	[\$/kgH2]	(PY,CY)	2005	2015	2050
Data				1	\$0.0170	\$0.0170
End				40	\$0.0170	\$0.0170
VarLinear	ByproductEfficiency	(Byproduct,CY)		2005	2050	
Data				2050		
End				2050		
		Byproduct Electricity		0.0000	0.0000	
		Steam		0.0000	0.0000	
VarLinear	Emissions	(Species,CY)		2005	2015	2025
Data				2050		
End				2050		
		Carbon		0	0	0
		GHG Equivalents		9.019096429	8.912899412	8.708093103
		NOx		0	0	0
		SOx		0	0	0
		Particulates (PM10)		0	0	0
		Mercury		0	0	0
VarLinear	ReplacementCosts	[\$]	(PY,CY)	2005	2015	2050
Data				1	\$903,547.15	\$677,660.36
End				40	\$903,547.15	\$677,660.36
Var	LearningFactor	(Technology,Factor)		IClass1(1) (I)	IClass2(2) (J)	IClass4(4) (L)
Data				1	5	3
End				1	5	2
VarData	InitialUnitNo	[unit # in CYBegin]		500		
VarData	LearningFactorStart			1		

Plant Description
Natural gas is fed to the plant from the pipeline at a pressure of 450 psia. The gas is generally sulfur-free, but odorizers with mercaptans 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 of a system of high alloy steel tubes. The reforming reaction is strongly endothermic, and the metallurgy of the tubes usually limits the reaction temperature to 1400-1700°F. The flue gas path of the fired reformer is integrated with additional boiler surfaces to produce about 700,000 lb/hour steam. Of this, about 450,000 lb/hour is superheated to 450 psia and 750°F, to be added to the incoming natural gas. Additional steam from the boiler is sent off-site. After the reformer, the process gas mixture of CO and H2 passes through a heat recovery step and is fed into a water gas shift reactor to produce additional H2. The Pressure Swing Adsorption (PSA) process is used for hydrogen purification, based on the ability to produce high purity hydrogen, low amounts of CO and CO2 and ease of operation. Shifted gas is fed directly to the PSA unit where hydrogen is purified up to approximately 99.6% based on the ability to produce high purity hydrogen, low amounts of CO and CO2 and ease of operation. Shifted gas is fed directly to the PSA unit where hydrogen is purified up to approximately 99.6%.

DTI projection from H2A and DTI/Ford Infrastructure Report (1996)

H2A has this as a % of DepreciableCapital+LandCosts

julie_perez: LHV

Consensus of data from H2A, ACP, H2Gen and Haldor Topsoe
4/23: H2A value is much lower at 0.7389.

julie_perez: 4/23: Previously 19.4592, similar to NG-SMR, CCS. Originally only 2005 number was anomaly.

SMR Catalyst @ \$7.00/lb, SCR @ \$10.00/lb, PSA Sorbent, Shift Catalyst @ \$5.24/lb

0.5% of DepreciableCapital

Each row corresponds to a technology sheet. Building one of the current sheet will decrease the cost of every technology listed by the corresponding "factor." The numbers in the first three columns are the 1st, 2nd and 4th numbers of the technology to be-changed's IClass var

All delivery (I=3) sheets with the same J share a LearningFactor (e.g., LT to 0.11PD and LT to 1.51PD only need one LearningFactor, since both sheets represent the same underlying technology - LTs). The L for this common factor should always be 1, and the factor should appear on every sheet that shares it.

Building an upper-bound FC ought to decrease the cost of a normal FC by the same amount. You would probably want a similar LearningFactor (maybe even a reference) on the normal FC sheet

Production: NG-SMR, CCS

NG-SMR, CCS

VarLinear

Data

End

Var

Data

End

VarData

VarData

ReplacementCosts

[S]

LearningFactor

InitialUnitNo

[unit # in CYBegin]

LearningFactorStart

(PY,CY)	2005	2015	2050
1	\$1,490,445.24	\$1,280,364.01	\$1,280,364.01
40	\$1,490,445.24	\$1,280,364.01	\$1,280,364.01

(Technology,Factor)

FC,NG-SMR,1.5 (UPPER)

FC,NG-SMR,1.5

IClass[1] (I)

IClass[2] (I)

IClass[4] (L)

Factor

1	5	3	1
500			
1			

Each row corresponds to a technology sheet.
Building one of the current sheet will decrease the cost of every technology listed by the corresponding "Factor." The numbers in the first three columns are the 1st, 2nd and 4th numbers of the technology to-be-cheapened's IClass var

All delivery (1-3) sheets with the same J share a LearningFactor (e.g., LT to 0.1TPD and LT to 1.5TPD only need one LearningFactor, since both sheets represent the same underlying technology LTs). The L for this common factor should always be 1, and the factor should appear on every sheet that shares it.

Building an upper-bound FC ought to decrease the cost of a normal FC by the same amount.
You would probably want a similar LearningFactor (maybe even a reference) on the normal FC sheet

5

0.5% of DepreciableCapital

0	Variable	[Units]	(y-axis,x-axis)	Data	Source Used
VarData	IClass	[1,5,1,1]		[1,5,1,1]	
VarData	OClass	[4,7,1]		[4,7,1]	
VarData	CVStart	[Year]		2005	33
VarData	CVStop	[Year]		2050	
Axis	CY	CY		2005-2050	
VarData	IRR	[%]		10%	33
VarData	DepreciationLength	[Years]		7	33
VarData	AnalysisPeriod	[Years]		10	
VarData	Life	[Years]		20	
Axis	PY	PY		[1-20]	
VarData	DesignCapacity	[kgH2/day]		100	33
VarData	DesignCapacity	[kgH2/year]		36,500	55
VarData	CapacityFactor	[% of DesignCapacity]		70%	33
VarData	Location			3	
VarData	DepreciableCapital (Direct)		(Component,CY)	2005 2015 2025	
VarData		(\$)		Uninstalled Costs \$278,588.91 \$278,588.91 \$278,588.91	5
VarData		(\$)		Installation Costs 10% 10% 10%	33
VarData		(\$)		Installed Costs \$306,447.80 \$306,447.80 \$306,447.80	
VarData	DepreciableCapital (Indirect)		(Component,CY)	2005 2015 2025	
VarData		(\$)		Interp. Uninstalled Costs \$278,588.91 \$278,588.91 \$278,588.91	
VarData		(\$)		Site Preparation \$34,128.00	33
VarData		(\$)		Engineering & Design \$15,000.00	5
VarData		(\$)		Process Contingency \$0.00	5
VarData		(\$)		Project Contingency 5%	55
VarData		(\$)		% of Installed Costs	
VarData		(\$)		Other Depreciable Capital \$0.00	33
VarData		(\$)		One-Time Licensing Fees \$0.00	33
VarData		(\$)		Up-Front Permitting Costs \$15,000.00	5
VarData	DepreciableCapital	(\$)	(CY)	2005 2015 2025 2050	
VarData		(\$)		\$385,898.19 \$385,898.19 \$385,898.19 \$385,898.19	
VarData	LandRequired	[acres]		0	
VarData	FixedOM		(Component)		
VarData		(hours/year)		FTEs 0	33
VarData		(\$/hour)		Labor Costs \$15.00	33
VarData		(\$/year)		Labor Costs \$47.08	
VarData		[% of Labor Cost]		Overhead and G&A 20%	33
VarData		[% of DepreciableCapital]		Property Tax & Insurance 2%	33
VarData		(\$/year)		Rent \$1,720.68	33
VarData		(\$/year)		Lic., Permits and Fees \$1,000.00	33
VarData		[% of Installed Costs]		Maint for Maint. & Repairs 7%	33
VarData		(\$/year)		Other Fees \$0.00	
VarData		(\$/year)		Other Fixed OM Costs \$0.00	
VarData	FixedOM	(\$/year)	(PY,CY)	2005 2015 2025 2050	
VarData		(\$/year)		\$31,946.49 \$31,946.49 \$31,946.49 \$31,946.49	
VarData	OtherFixed	(\$/year)	(PY,CY)	2005 2050	
VarData		(\$/year)		\$0.00 \$0.00	
VarData	FeedstockEfficiency		(Feedstock,CY)	2005 2015 2025 2050	
VarData				\$0.00 \$0.00	
Data		[GJH2/GJFeedstock]		Commercial Natural Gas 0.6803 0.7702 0.7702	2005: 33 2015: 34 2025: 35
Data		[GJH2/GJFeedstock]		Industrial Natural Gas 0.0000 0.0000 0.0000	
Data		[GJH2/GJFeedstock]		Electric Utility Natural Gas 0.0000 0.0000 0.0000	
Data		[GJH2/GJ]		Commercial Electricity 14.0593 19.2813 19.2813	2005: 33 2015: 34 2025: 35
Data		[GJH2/GJFeedstock]		Industrial Electricity 0.0000 0.0000 0.0000	
Data		[GJH2/GJFeedstock]		Utility Steam Coal (Central) 0.0000 0.0000 0.0000	
Data		[GJH2/GJFeedstock]		Diesel Fuel 0.0000 0.0000 0.0000	
Data		[GJH2/GJFeedstock]		Biomass 0.0000 0.0000 0.0000	
Data		[GJH2/GJFeedstock]		Ethanol 0.0000 0.0000 0.0000	
Data		[GJH2/GJFeedstock]		Methanol 0.0000 0.0000 0.0000	
Data		[GJH2/GJFeedstock]		Gasoline 0.0000 0.0000 0.0000	
Data		[GJH2/GJFeedstock]		Steam 0.0000 0.0000 0.0000	
Data		[GJH2/L]		Cooling Water 0.0000 0.0000 0.0000	
Data		[GJH2/L]		Demineralized Water 0.0000 0.0000 0.0000	
Data		[GJH2/L]		Process Water 0.0054 0.0054 0.0054	2005: 33 2015: 34 2025: 35
Data		[GJH2/Barrel]		Bio-oil 0.0000 0.0000 0.0000	
Data		[GJH2/GJFeedstock]		Utility Steam Coal (Regional) 0.0000 0.0000 0.0000	
Data		[GJH2/GJFeedstock]		MSW (1) 0.0000 0.0000 0.0000	
Data		[GJH2/GJFeedstock]		MSW (2) 0.0000 0.0000 0.0000	
End	OtherVariableOM		(Component)		
VarData		(\$/year) @ capacity		WT Costs \$0.00	33
VarData		(\$/year) @ capacity		SWD Costs \$0.00	
VarData		(\$/year) @ capacity		Other Variable Op. Costs \$600.00	
VarData		(\$/year) @ capacity		Royalties \$0.00	
VarData		(\$/year) @ capacity		Operator Profit \$0.00	
VarData		(\$/year) @ capacity		Subsidies, Tax Incentives \$0.00	
VarData		(\$/year) @ capacity		CO2 Separation & Seq. \$0.00	
VarData	OtherVariableOM	(\$/kgH2)	(PY,CY)	2005 2050	
VarData		(\$/kgH2)		\$0.0235 \$0.0235	
VarData	ByproductEfficiency		(Byproduct,CY)	2005 2050	
VarData		[GJH2/GJ]		Byproduct Electricity 0.0000 0.0000	
VarData		[GJH2/GJFeedstock]		Steam 0.0000 0.0000	
VarData	Emissions	[kg/kgH2]	(Species,CY)	2005 2015 2025 2050	
VarData				Carbon 0 0 0 0	
VarData				GHG Equivalents 11.13623823 #DIV/0! 9.837075372 9.837075372	19
VarData				NOx 0 0 0 0	
VarData				SOx 0 0 0 0	
VarData				Particulates (PM10) 0 0 0 0	
VarData				Mercury 0 0 0 0	
VarData	ReplacementCosts	(\$)	(PY,CY)	2005 2006 2007 2008 2009 2010 2011 2012 2013 2014 2015 2016 2017	
VarData				1 \$0.00 \$0.00 \$0.00 \$0.00 \$0.00 \$0.00 \$0.00 \$0.00 \$0.00 \$0.00 \$0.00 \$0.00	
VarData				5 \$0.00 \$0.00 \$0.00 \$0.00 \$0.00 \$0.00 \$0.00 \$0.00 \$0.00 \$0.00 \$0.00 \$0.00	
VarData				6 \$41,788.34 \$41,788.34 \$41,788.34 \$41,788.34 \$41,788.34 \$41,788.34 \$41,788.34 \$41,788.34 \$41,788.34 \$41,788.34 \$41,788.34 \$41,788.34	
VarData				7 \$0.00 \$0.00 \$0.00 \$0.00 \$0.00 \$0.00 \$0.00 \$0.00 \$0.00 \$0.00 \$0.00 \$0.00	
VarData				10 \$0.00 \$0.00 \$0.00 \$0.00 \$0.00 \$0.00 \$0.00 \$0.00 \$0.00 \$0.00 \$0.00 \$0.00	
VarData				11 \$306,447.80 \$306,447.80 \$41,788.34 \$41,788.34 \$41,788.34 \$41,788.34 \$41,788.34 \$41,788.34 \$41,788.34 \$41,788.34 \$41,788.34 \$41,788.34	
VarData				12 \$0.00 \$0.00 \$264,659.46 \$264,659.46 \$0.00 \$0.00 \$0.00 \$0.00 \$0.00 \$0.00 \$0.00 \$0.00	
VarData				13 \$0.00 \$0.00 \$0.00 \$0.00 \$264,659.46 \$264,659.46 \$0.00 \$0.00 \$0.00 \$0.00 \$0.00 \$0.00	
VarData				14 \$0.00 \$0.00 \$0.00 \$0.00 \$0.00 \$0.00 \$264,659.46 \$264,659.46 \$0.00 \$0.00 \$0.00 \$0.00	
VarData				15 \$0.00 \$0.00 \$0.00 \$0.00 \$0.00 \$0.00 \$0.00 \$0.00 \$264,659.46 \$264,659.46 \$0.00 \$0.00	
VarData				16 \$41,788.34 \$41,788.34 \$41,788.34 \$41,788.34 \$41,788.34 \$41,788.34 \$41,788.34 \$41,788.34 \$41,788.34 \$41,788.34 \$306,447.80 \$306,447.80	
VarData				17 \$0.00 \$0.00 \$0.00 \$0.00 \$0.00 \$0.00 \$0.00 \$0.00 \$0.00 \$0.00 \$0.00 \$0.00	
VarData				18 \$0.00 \$0.00 \$0.00 \$0.00 \$0.00 \$0.00 \$0.00 \$0.00 \$0.00 \$0.00 \$0.00 \$0.00	
VarData				19 \$0.00 \$0.00 \$0.00 \$0.00 \$0.00 \$0.00 \$0.00 \$0.00 \$0.00 \$0.00 \$0.00 \$0.00	
VarData				20 \$0.00 \$0.00 \$0.00 \$0.00 \$0.00 \$0.00 \$0.00 \$0.00 \$0.00 \$0.00 \$0.00 \$0.00	
VarData	LearningFactor		(Technology, Factor)	IClass[1] (1) IClass[2] (1) IClass[4] (1) Factor	
VarData				FC-NG-SMR,0.1 1 5 2 0.97	5
VarData	InitialUnitNo	[unit # in CYBegin]		180	5
VarData	LearningFactorStart			0.795968308	5
VarData	ExternalBuildFixed		(CY)	2005 2011 2012 2050	
VarData				0 0 50 50	
VarData	ExternalBuildVariable			1	5

Plant Description
The natural gas reforming process is based on 15-atm SMR with hydro-desulfurization pre-treatment and PSA gas cleanup. The PSA is based on 4 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. The product hydrogen exits the PSA at 300psi and is compressed and stored at 6250psi for cascade filling of vehicles.

This price is reflective of the 180 unit which is projected for 2012. Because we are using the learning curve with this production method, we cannot use the H2A price for the 500th unit.

Uninstalled Costs cubically interp'd in MATLAB. Needed for ReplacementCosts.

Previously 13% of H2A value to reflect contribution of production component to H2A total. Changed to full H2A value of \$34,128 based on H2Gen input.

Previously 13% of H2A value to reflect contribution of production component to H2A total. Changed to 50% of H2A value to better reflect cost split between production and dispensing.

Previously 13% of H2A value to reflect contribution of production component to H2A total. Changed to 50% of H2A value to better reflect cost split between production and dispensing.

Based off of a detailed site plan for a 2206 ft² station (100kg/day); assumes 5.50t/month. 13% of H2A value to reflect contribution of production component to H2A total.

Catalyst: 15% of Uninstalled Costs: Lifetime = 5 years.

Catalyst = reformer

Catalyst: 15% of Uninstalled Costs: Lifetime = 5 years.

Catalyst: 15% of Uninstalled Costs: Lifetime = 5 years. (BD.)

Reformer: Installed Costs-15% of Uninstalled Costs: Lifetime = 10/15/20 yrs. In 05/15/30

End-of-life salvage value: Reformer price x % of Reformer lifetime remaining.

Building an upper bound FC ought to decrease the cost of a normal FC by the same amount.

You would probably want a similar LearningFactor (maybe even a reference) on the normal FC sheet

Each row corresponds to a technology sheet. Building one of the current sheet will decrease the cost of every technology listed by the corresponding "Factor". The numbers in the first three columns are the 1st, 2nd and 4th numbers of the technology to be cheapened's IClass var

All delivery (I=3) sheets with the same J share a LearningFactor (e.g., LT to 0.1TPD and LT to 1.5TPD only need one LearningFactor, since both sheets represent the same underlying technology - LT). The LT for this common factor should always be 1, and the factor should appear on every sheet that shares it.

2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
\$276,588.91	\$276,588.91	\$276,588.91	\$276,588.91	\$276,588.91	\$276,588.91	\$276,588.91	\$276,588.91	\$276,588.91	\$276,588.91	\$276,588.91	\$276,588.91	\$276,588.91

2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2030
\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00
\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00
\$41,788.34	\$41,788.34	\$41,788.34	\$41,788.34	\$41,788.34	\$41,788.34	\$41,788.34	\$41,788.34	\$41,788.34	\$41,788.34	\$41,788.34	\$41,788.34	\$41,788.34	\$41,788.34
\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00
\$41,788.34	\$41,788.34	\$41,788.34	\$41,788.34	\$41,788.34	\$41,788.34	\$41,788.34	\$41,788.34	\$41,788.34	\$41,788.34	\$41,788.34	\$41,788.34	\$41,788.34	\$41,788.34
\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00
\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00
\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00
\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00
\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00
\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00
\$41,788.34	\$41,788.34	\$41,788.34	\$41,788.34	\$41,788.34	\$41,788.34	\$41,788.34	\$41,788.34	\$41,788.34	\$41,788.34	\$41,788.34	\$41,788.34	\$41,788.34	\$41,788.34
\$264,659.46	\$264,659.46	\$264,659.46	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00
\$0.00	\$0.00	\$0.00	\$264,659.46	\$264,659.46	\$264,659.46	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00
\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$264,659.46	\$264,659.46	\$264,659.46	\$264,659.46	\$0.00	\$0.00	\$0.00	\$0.00
-\$198,494.60	-\$198,494.60	-\$198,494.60	-\$217,954.85	-\$217,954.85	-\$217,954.85	-\$235,252.86	-\$235,252.86	-\$235,252.86	\$13,929.45	\$13,929.45	\$13,929.45	\$0.00	\$0.00

Production: FC,NG-SMR,1.5 (LCLB)

FC,NG-SMR,1.5 (LCLB)

2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
\$1,001,671.83	\$1,001,671.83	\$1,001,671.83	\$1,001,671.83	\$1,001,671.83	\$1,001,671.83	\$1,001,671.83	\$1,001,671.83	\$1,001,671.83	\$1,001,671.83	\$1,001,671.83	\$1,001,671.83	\$1,001,671.83

2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2050
\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00
\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00
\$150,250.77	\$150,250.77	\$150,250.77	\$150,250.77	\$150,250.77	\$150,250.77	\$150,250.77	\$150,250.77	\$150,250.77	\$150,250.77	\$150,250.77	\$150,250.77	\$150,250.77	\$150,250.77
\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00
\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00
\$150,250.77	\$150,250.77	\$150,250.77	\$150,250.77	\$150,250.77	\$150,250.77	\$150,250.77	\$150,250.77	\$150,250.77	\$150,250.77	\$150,250.77	\$150,250.77	\$150,250.77	\$150,250.77
\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00
\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00
\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00
\$150,250.77	\$150,250.77	\$150,250.77	\$150,250.77	\$150,250.77	\$150,250.77	\$150,250.77	\$150,250.77	\$150,250.77	\$150,250.77	\$150,250.77	\$150,250.77	\$150,250.77	\$150,250.77
\$951,588.24	\$951,588.24	\$951,588.24	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00
\$0.00	\$0.00	\$0.00	\$951,588.24	\$951,588.24	\$951,588.24	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00
\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$951,588.24	\$951,588.24	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00
\$-713,691.18	\$-713,691.18	\$-713,691.18	\$-783,660.90	\$-783,660.90	\$-783,660.90	\$-845,856.21	\$-845,856.21	\$-845,856.21	\$50,083.59	\$50,083.59	\$50,083.59	\$0.00	\$0.00

0	Variable	[Units]	(y-axis,x-axis)	Data	Source Used
VarData	IClass			[1,5,1,3]	
VarData	OClass			[4,8,1]	
VarData	CYStart	[Year]		2005	
VarData	CYStop	[Year]		2050	
Axis	CY	CY		2005-2050	
VarData	IRR	[%]		10%	
VarData	DepreciationLength	[Years]		7	
VarData	AnalysisPeriod	[Years]		10	
VarData	Life	[Years]		20	
Axis	PY	PY		[1-20]	
VarData	DesignCapacity	[kgH2/day]		1,500	
VarData	DesignCapacity	[kgH2/year]		547,500	
VarData	CapacityFactor	[% of DesignCapacity]		70%	
VarData	Location			3	
VarData	DepreciableCapital (Direct)		(Component,CY)	2005	
VarData		[\$]	Uninstalled Costs	\$1,001,671.83	
VarData		[\$]	Installation Costs	\$1,178,392.01	
VarData	DepreciableCapital (Indirect)		(Component,CY)	2005	
VarData		[\$]	Interp. Uninstalled Costs	\$1,001,671.83	
VarData		[\$]	Site Preparation	\$650,000.00	
VarData		[\$]	Engineering & Design	\$15,000.00	
VarData		[\$]	Process Contingency	\$0.00	
VarData		[% of Installed Costs]	Project Contingency	5%	
VarData		[\$]	Other Depreciable Capital	\$0.00	
VarData		[\$]	One-Time Licensing Fees	\$0.00	
VarData		[\$]	Up-Front Permitting Costs	\$15,000.00	
VarData	DepreciableCapital	[\$]	(CY)	2005	
VarData			2050	\$2,243,254.58	
VarData	LandRequired	[acres]		0	
VarData	FixedOM		(Component)		
VarData		[hours/year]	FTEs	0	
VarData		[\$/hour]	Labor Costs	\$15.00	
VarData		[\$/year]	Labor Costs	\$0.00	
VarData		[% of Labor Cost]	Overhead and G&A	20%	
VarData		[% of DepreciableCapital]	Property Tax & Insurance	2%	
VarData		[\$/year]	Rent	\$5,615.22	
VarData		[\$/year]	Lic., Permits and Fees	\$1,000.00	
VarData		[% of Installed Costs]	Matl for Maint. & Repairs	5%	
VarData		[\$/year]	Other Fees	\$0.00	
VarData		[\$/year]	Other Fixed OM Costs	\$0.00	
VarData	FixedOM	[\$/year]	(PY,CY)	2005	
VarData			2050	\$110,399.91	
VarData	OtherFixed	[\$/year]	(PY,CY)	2005	
VarData			2050	\$110,399.91	
VarData	FeedstockEfficiency		(Feedstock,CY)	2005	
VarData		[GJH2/GJFeedstock]	Commercial Natural Gas	0.0000	
VarData		[GJH2/GJFeedstock]	Industrial Natural Gas	0.7200	
VarData		[GJH2/GJFeedstock]	Electric Utility Natural Gas	0.0000	
VarData		[GJH2/GJ]	Commercial Electricity	22.4948	
VarData		[GJH2/GJ]	Industrial Electricity	0.0000	
VarData		[GJH2/GJFeedstock]	Jillity Steam Coal (Central)	0.0000	
VarData		[GJH2/GJFeedstock]	Diesel Fuel	0.0000	
VarData		[GJH2/GJFeedstock]	Biomass	0.0000	
VarData		[GJH2/GJFeedstock]	Ethanol	0.0000	
VarData		[GJH2/GJFeedstock]	Methanol	0.0000	
VarData		[GJH2/GJFeedstock]	Gasoline	0.0000	
VarData		[GJH2/GJFeedstock]	Steam	0.0000	
VarData		[GJH2/L]	Cooling Water	0.0000	
VarData		[GJH2/L]	Demineralized Water	0.0000	
VarData		[GJH2/L]	Process Water	0.0054	
VarData		[GJH2/Barrel]	Bit-Oil	0.0000	
VarData		[GJH2/GJFeedstock]	Jillity Steam Coal (Regional)	0.0000	
VarData		[GJH2/GJFeedstock]	MSW (1)	0.0000	
VarData		[GJH2/GJFeedstock]	MSW (2)	0.0000	
VarData	OtherVariableOM		(Component)		
VarData		[\$/year @ capacity]	WT Costs	\$0.00	
VarData		[\$/year @ capacity]	SWD Costs	\$0.00	
VarData		[\$/year @ capacity]	Other Variable Op. Costs	\$1,800.00	
VarData		[\$/year @ capacity]	Royalties	\$0.00	
VarData		[\$/year @ capacity]	Operator Profit	\$0.00	
VarData		[\$/year @ capacity]	Subsidies, Tax Incentives	\$0.00	
VarData		[\$/year @ capacity]	CO2 Separation & Seq.	\$0.00	
VarData	OtherVariableOM	[\$/kgH2]	(PY,CY)	2005	
VarData			2050	\$0.0047	
VarData	ByproductEfficiency		(Byproduct,CY)	2005	
VarData		[GJH2/GJ]	Byproduct Electricity	0.0000	
VarData		[GJH2/GJFeedstock]	Steam	0.0000	
VarData	Emissions	[kg/kgH2]	(Species,CY)	2005	
VarData			Carbon	0	
VarData			GHG Equivalents	10.52227917	
VarData			NOX	0	
VarData			SOX	0	
VarData			Particulates (PM10)	0	
VarData			Mercury	0	
VarData	ReplacementCosts	[\$]	(PY,CY)	2005	
VarData			2006	\$0.00	
VarData			2007	\$0.00	
VarData			2008	\$0.00	
VarData			2009	\$0.00	
VarData			2010	\$0.00	
VarData			2011	\$0.00	
VarData			2012	\$0.00	
VarData			2013	\$0.00	
VarData			2014	\$0.00	
VarData			2015	\$0.00	
VarData			2016	\$0.00	
VarData			2017	\$0.00	
VarData			2018	\$0.00	
VarData			2019	\$0.00	
VarData			2020	\$0.00	
VarData			2021	\$0.00	
VarData			2022	\$0.00	
VarData			2023	\$0.00	
VarData			2024	\$0.00	
VarData			2025	\$0.00	
VarData			2026	\$0.00	
VarData			2027	\$0.00	
VarData			2028	\$0.00	
VarData			2029	\$0.00	
VarData			2030	\$0.00	
VarData			2031	\$0.00	
VarData			2032	\$0.00	
VarData			2033	\$0.00	
VarData			2034	\$0.00	
VarData			2035	\$0.00	
VarData			2036	\$0.00	
VarData			2037	\$0.00	
VarData			2038	\$0.00	
VarData			2039	\$0.00	
VarData			2040	\$0.00	
VarData			2041	\$0.00	
VarData			2042	\$0.00	
VarData			2043	\$0.00	
VarData			2044	\$0.00	
VarData			2045	\$0.00	
VarData			2046	\$0.00	
VarData			2047	\$0.00	
VarData			2048	\$0.00	
VarData			2049	\$0.00	
VarData			2050	\$0.00	
VarData	LearningFactor		(Technology Factor)		
VarData			FC,NG-SMR,1.5 (UPPER)	1	
VarData			FC,NG-SMR,0.1	3	
VarData	InitialUnitNo	[unit # in CYBegin]		0.95287009	
VarData	LearningFactorStart		(CY)	2005	
VarData	ExternalBuildFixed	[units]		0	
VarData	ExternalBuildVariable			1	

Plant Description
The natural gas reforming process is based on 20-atm conventional tube-in-shell Steam Methane Reformer (SMR) with hydro-desulfurization pre-treatment and PSA gas cleanup. The PSA is based on 4 bed Blatta 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. Because smaller units are more amenable to factory building than very large units, two 750kgH2/day reactors are assumed rather than a single 1500kg/day unit. The system is assumed to be air cooled (and thus requires no cooling water flow). The product hydrogen exits the PSA at 300psi and is compressed and stored at 6350-psi cascade filling of vehicles.

Because we are using the learning curve for this production method, we cannot use the 500 unit price provided by H2A.

Industrial Gas Supplier cost estimate is \$76,553 higher than DTR's H2A case.

Uninstalled Costs cubically interp'd in MATLAB. Needed for ReplacementCosts.

Changed to full H2A value of \$74,344 based on H2Gen input. An additional \$575,656 is included to reflect additional estimate of IG supplier.

Changed to 50% of H2A value to better reflect cost split between production and dispensing.

Changed to 50% of H2A value to better reflect cost split between production and dispensing.

This is multiplied by a 17% factor to make total pathway 10% higher cost than all quotes, a true upper bound.

Based off of a detailed site plan for a 7199 ft² station (1500kg/day), assumes \$50/ft²/month. 13% of H2A value to reflect contribution of production component to H2A total.

Consensus of data from H2A, ACPI, H2Gen and H2A Topos.

This differs from the H2A predicted consumption of 12.7 liters per kg H2 which we consider to be erroneous.

This covers waste disposal costs, non-feedstock fuels, environmental surcharges, etc. and is estimated at \$800/month with 50% being attributed to refueling operations (the other 50% goes to convenience store operations) and is further pro-rata for the fraction of hydrogen dispensers out of total dispensers (1 out of 8 for large stations, 1 out of 8 for small stations). Thus for a large station, annual "Other Variable Costs" are \$800/month * 12 months/year * 50% fueling fraction * (1 H2 dispenser/8 total dispensers) = \$1,800/year.

Catalyst: 15% of Uninstalled Costs: Lifetime = 5 years.

Catalyst + reformer

Catalyst: 15% of Uninstalled Costs: Lifetime = 5 years.

All delivery (1-3) sheets with the same 1 share a LearningFactor (e.g., LT to 0.1TPD and LT to 1.5TPD only need one LearningFactor, since both sheets represent the same underlying technology - LT). The LT for this common factor should always be 1, and the factor should appear on every sheet that shares it.

End-of-life salvage value: Reformer price x % of Reformer lifetime remaining.

Each row corresponds to a technology sheet. Building one of the current sheet will decrease the cost of every technology listed by the corresponding "Factor". The numbers in the first three columns are the 1st, 2nd and 4th numbers of the technology to be-chosen's IClass var

Building an upper-bound FC ought to decrease the cost of a normal FC by the same amount. You would probably want a similar LearningFactor (maybe even a reference) on the normal FC sheet

2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
				\$1,001,671.53		\$1,001,671.53					

2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2050
\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00
\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00
\$150,250.77	\$150,250.77	\$150,250.77	\$150,250.77	\$150,250.77	\$150,250.77	\$150,250.77	\$150,250.77	\$150,250.77	\$150,250.77	\$150,250.77	\$150,250.77	\$150,250.77
\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00
\$150,250.77	\$150,250.77	\$150,250.77	\$150,250.77	\$150,250.77	\$150,250.77	\$150,250.77	\$150,250.77	\$150,250.77	\$150,250.77	\$150,250.77	\$150,250.77	\$150,250.77
\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00
\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00
\$150,250.77	\$150,250.77	\$150,250.77	\$150,250.77	\$150,250.77	\$150,250.77	\$150,250.77	\$150,250.77	\$150,250.77	\$150,250.77	\$150,250.77	\$150,250.77	\$150,250.77
\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00
\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00
\$150,250.77	\$150,250.77	\$150,250.77	\$150,250.77	\$150,250.77	\$150,250.77	\$150,250.77	\$150,250.77	\$150,250.77	\$150,250.77	\$150,250.77	\$150,250.77	\$150,250.77
\$951,588.24	\$951,588.24	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00
\$0.00	\$0.00	\$951,588.24	\$951,588.24	\$951,588.24	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00
\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$951,588.24	\$951,588.24	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00
-\$713,691.18	-\$713,691.18	-\$783,660.90	-\$783,660.90	-\$783,660.90	-\$845,856.21	-\$845,856.21	-\$845,856.21	\$50,083.59	\$50,083.59	\$50,083.59	\$0.00	\$0.00

Production: FC,MMEL-E,0.1

VarData

IClass

[1,5,1,4]

VarData

OClass

[4,7,1]

VarData

CYStart

[Year]

VarData

CYStop

[Year]

Axis

CY

[2005-2050]

VarData

RR

[CY]

VarData

DepreciationLength

[Years]

VarData

AnalysisPeriod

[Years]

VarData

Life

[Years]

Axis

PV

[1-20]

VarData

DesignCapacity

[kgH2/day]

VarData

DesignCapacity

[kgH2/year]

VarData

CapacityFactor

[% of DesignCapacity]

VarData

Location

VarData

DepreciableCapital (Direct)

(Component,CY)

2005

2015

2025

2050

Baseline Costs

\$1,419.00

\$854.00

\$640.00

Uninstalled Costs

\$315,727.50

\$170,444.17

\$119,200.00

Installation Costs

10%

10%

10%

Installed Costs

\$347,300.25

\$187,488.58

\$131,120.00

2005

2015

2025

2050

Site Preparation

\$34,128.00

Engineering & Design

\$15,000.00

Process Contingency

\$0.00

Project Contingency

5%

Other Depreciable Capital

\$0.00

One-Time Licensing Fees

\$0.00

Up-Front Permitting Costs

\$15,000.00

2005

2015

2025

2050

\$428,793.26

\$260,991.74

\$201,804.00

\$201,804.00

0

FTL

0

Labor Costs

\$15.00

Labor Costs

\$0.00

Overhead and G&A

20%

Property Tax & Insurances

2%

Rent

\$1,720.68

Lic. Permits and Fees

\$1,000.00

M&I for Maint. & Repairs

7%

Other Fees

\$0.00

Other Fixed O&M Costs

\$0.00

2005

2015

2025

2050

\$35,607.56

\$21,064.70

\$15,935.16

\$15,935.16

2005

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\$0.00

\$0.00

2005

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Commercial Natural Gas

0.0000

0.0000

0.0000

0.0000

Industrial Natural Gas

0.0000

0.0000

0.0000

0.0000

Electric Utility Natural Gas

0.0000

0.0000

0.0000

0.0000

Commercial Electricity

0.0000

0.0000

0.0000

0.0000

Industrial Electricity

0.6319

0.7044

0.7549

0.7549

Utility Steam Coal (Central)

0.0000

0.0000

0.0000

0.0000

Diesel Fuel

0.0000

0.0000

0.0000

0.0000

Biomass

0.0000

0.0000

0.0000

0.0000

Ethanol

0.0000

0.0000

0.0000

0.0000

Methanol

0.0000

0.0000

0.0000

0.0000

Gasoline

0.0000

0.0000

0.0000

0.0000

Steam

0.0000

0.0000

0.0000

0.0000

Cooling Water

0.0001

0.0001

0.0001

0.0001

Demineralized Water

0.0109

0.0109

0.0109

0.0109

Process Water

0.0000

0.0000

0.0000

0.0000

Boiler

0.0000

0.0000

0.0000

0.0000

Utility Steam Coal (Regional)

0.0000

0.0000

0.0000

0.0000

MSW (1)

0.0000

0.0000

0.0000

0.0000

MSW (2)

0.0000

0.0000

0.0000

0.0000

WT Costs

\$0.00

SWD Costs

\$0.00

Other Variable Op. Costs

\$600.00

Royalties

\$0.00

Operator Profit

\$0.00

Subsidies, Tax Incentives

\$0.00

CO2 Separation & Seq.

\$0.00

2005

2050

\$0.0235

\$0.0235

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\$94,718.25

\$51,133.25

\$35,760.00

\$35,760.00

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\$94,718.25

\$51,133.25

\$35,760.00

\$35,760.00

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FC-NG-SMR-1.5 (UPPER)

FC-NG-SMR-1.5

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Production: FC,MMEL-E,1.5

FC,MMEL-E,1.5

Production: FC,ETH,1.5

FC.ETH.1.5

2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
\$976,434.22	\$970,514.22	\$963,089.17	\$955,222.54	\$946,857.02	\$937,262.50	\$926,244.05	\$914,002.97	\$901,276.54	\$888,068.04	\$874,300.77	\$859,017.98	\$842,583.00

2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2060
\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00
\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00
\$146,765.13	\$145,575.63	\$144,463.38	\$143,433.35	\$142,490.55	\$141,639.97	\$140,886.61	\$140,235.45	\$139,691.48	\$139,259.71	\$138,945.11	\$138,752.70	\$138,687.45	\$138,687.45
\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00
\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00
\$146,765.13	\$145,575.63	\$144,463.38	\$143,433.35	\$142,490.55	\$141,639.97	\$140,886.61	\$140,235.45	\$139,691.48	\$139,259.71	\$138,945.11	\$138,752.70	\$138,687.45	\$138,687.45
\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00
\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00
\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00
\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00
\$146,765.13	\$145,575.63	\$144,463.38	\$143,433.35	\$142,490.55	\$141,639.97	\$140,886.61	\$140,235.45	\$139,691.48	\$139,259.71	\$138,945.11	\$138,752.70	\$138,687.45	\$138,687.45
\$929,512.51	\$921,979.01	\$914,934.71	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00
\$0.00	\$0.00	\$0.00	\$908,411.22	\$902,440.17	\$897,053.17	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00
\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$892,297.85	\$888,157.82	\$884,712.71	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00
\$-697,134.38	\$-691,484.26	\$-686,201.03	\$-748,103.36	\$-743,186.02	\$-738,749.67	\$-793,139.42	\$-789,473.62	\$-786,411.30	\$46,419.90	\$46,315.04	\$46,250.90	\$0.00	\$0.00

0	Variable	[Units]	(y-axis,x-axis)	Data	Source Used
VarData	IClass			[1,6,1,1]	
VarData	OClass			[2,1,-1]	
VarData	CYStart	[Year]		2015	
VarData	CYStop	[Year]		2050	
Axis	CY	CY		[2015-2050]	
VarData	IRR	[%]		10%	14
VarData	DepreciationLength	[Years]		20	14
VarData	AnalysisPeriod	[Years]		20	
VarData	Life	[Years]		40	14
Axis	PY	PY		[1-40]	
VarData	DesignCapacity	[kgH2/day]		672.693	14
VarData	DesignCapacity	[kgH2/year]		245,532.945	
VarData	CapacityFactor	[% of DesignCapacity]		90%	14
VarData	Location			1	
VarData	DepreciableCapital		(Component)		
VarData			ALWR Electric Plant, 1350MW	\$1,525,870,500.00	14
VarData			647 Electrolysis Modules @ 1047 kgH2/day Capacity	\$648,000,000.00	14
VarData			Plant Heat Rejection Subsystem	\$27,260,100.00	14
VarData	DepreciableCapital	[\$]	(CY)	2015 2050	
VarData				\$2,291,130,600.00 \$2,201,130,600.00	
VarData	LandRequired	[acres]		400	14
VarData	FixedOM		(Component)		
VarData		[hours/year]	FTEs	574	14
VarData		[\$/hour]	Labor Costs	\$50.00	14
VarData		[\$/year]	Labor Costs	\$59,696,000.00	14
VarData		[% of Labor Cost]	Overhead and G&A	20%	14
VarData		[% of DepreciableCapital]	Property Tax & Insurance	2%	14
VarData		[\$/year]	Rent	\$0.00	
VarData		[\$/year]	Lic., Permits and Fees	\$0.00	
VarData		[\$/year]	Matl for Maint. & Repairs	\$50,107,200.00	14
VarData		[\$/year]	Other Fees	\$0.00	
VarData		[\$/year]	Other Fixed O&M Costs	\$3,300,000.00	14
VarData	FixedOM	[(PY,CY)]		2015 2050	
VarData				1 \$169,065,012.00 \$169,065,012.00	
VarData				40 \$169,065,012.00 \$169,065,012.00	
VarData	OtherFixed	[(PY,CY)]		2015 2050	
VarData				1 \$0.00 \$0.00	
VarData				40 \$0.00 \$0.00	
VarData	FeedstockEfficiency		(Feedstock,CY)	2015 2050	
VarData		[GJH2/GJFeedstock]	Commercial Natural Gas	0.0000 0.0000	
VarData		[GJH2/GJFeedstock]	Industrial Natural Gas	0.0000 0.0000	
VarData		[GJH2/GJFeedstock]	Electric Utility Natural Gas	0.0000 0.0000	
VarData		[GJH2/GJ]	Commercial Electricity	0.0000 0.0000	
VarData		[GJH2/GJ]	Industrial Electricity	0.0000 0.0000	
VarData		[GJH2/GJFeedstock]	Jillity Steam Coal (Central)	0.0000 0.0000	
VarData		[GJH2/GJFeedstock]	Diesel Fuel	0.0000 0.0000	
VarData		[GJH2/GJFeedstock]	Biomass	0.0000 0.0000	
VarData		[GJH2/GJFeedstock]	Ethanol	0.0000 0.0000	
VarData		[GJH2/GJFeedstock]	Methanol	0.0000 0.0000	
VarData		[GJH2/GJFeedstock]	Gasoline	0.0000 0.0000	
VarData		[GJH2/GJFeedstock]	Steam	0.0000 0.0000	
VarData		[GJH2/L]	Cooling Water	0.0000 0.0000	
VarData		[GJH2/L]	Demineralized Water	0.0109 0.0109	
VarData		[GJH2/L]	Process Water	0.0000 0.0000	
VarData		[GJH2/Barrel]	Bio-oil	0.0000 0.0000	
VarData		[GJH2/GJFeedstock]	Jillity Steam Coal (Regional)	0.0000 0.0000	
VarData		[GJH2/GJFeedstock]	MSW (1)	0.0000 0.0000	
VarData		[GJH2/GJFeedstock]	MSW (2)	0.0000 0.0000	
VarData	OtherVariableOM		(Component)		
VarData		[\$/year] @ capacity	WT Costs	\$0.00	
VarData		[\$/year] @ capacity	SWD Costs	\$0.00	
VarData		[\$/year] @ capacity	Other Variable Op. Costs	\$72,407,300.00	14
VarData		[\$/year] @ capacity	Royalties	\$0.00	
VarData		[\$/year] @ capacity	Operator Profit	\$0.00	
VarData		[\$/year] @ capacity	Subsidies, Tax Incentives	\$0.00	
VarData		[\$/year] @ capacity	CO2 Separation & Seq.	\$0.00	
VarData	OtherVariableOM	[(PY,CY)]		2015 2050	
VarData				1 \$0.3277 \$0.3277	
VarData				40 \$0.3277 \$0.3277	
VarData	ByproductEfficiency		(Byproduct,CY)	2015 2050	
VarData		[GJH2/GJ]	Byproduct Electricity	0.0000 0.0000	
VarData		[GJH2/GJFeedstock]	Steam	0.0000 0.0000	
VarData	Emissions		(Species,CY)	2015 2050	
VarData		[kg/kgH2]	Carbon	0 0	
VarData			GHG Equivalents	0 0	
VarData			NOX	0 0	
VarData			SOX	0 0	
VarData			Particulates (PM10)	0 0	
VarData			Mercury	0 0	
VarData	ReplacementCosts	[\$]	(PY,CY)	2015 2050	
VarData				1 \$11,005,653.00 \$11,005,653.00	
VarData				9 \$11,005,653.00 \$11,005,653.00	
VarData				10 \$205,405,653.00 \$205,405,653.00	
VarData				11 \$11,005,653.00 \$11,005,653.00	
VarData				19 \$11,005,653.00 \$11,005,653.00	
VarData				20 \$205,405,653.00 \$205,405,653.00	
VarData				21 \$11,005,653.00 \$11,005,653.00	
VarData				29 \$11,005,653.00 \$11,005,653.00	
VarData				30 \$205,405,653.00 \$205,405,653.00	
VarData				31 \$11,005,653.00 \$11,005,653.00	
VarData				40 \$11,005,653.00 \$11,005,653.00	
VarData	LearningFactor		(Technology, Factor)	IClass[1] (L) IClass[2] (L) IClass[4] (L) Factor	
VarData			FC-NG-SMR,1.5 (UPPER)	1 5 3 1	
VarData			FC-NG-SMR,1.5	1 5 2 1	
VarData	InitialUnitNo	[unit # in CYBegin]		500	
VarData	LearningFactorStart			1	

Plant Description
The system examined is based on the application of current nuclear energy for hydrogen production, specifically an Advanced Light Water Reactor (ALWR) providing electric power to a high pressure water electrolysis plant.

julie_perez: Installed Cost. Overall installation cost factor is about 20% of uninstalled costs.

julie_perez: Installed Cost. Overall installation cost factor is about 20% of uninstalled costs.

julie_perez: Installed Cost. Overall installation cost factor is about 20% of uninstalled costs.

H2A has this as a % of DepreciableCapital+LandCosts

\$29,475,900 for Nuclear Power Plant+\$20,631,300 for Electrolysis Plant

Nuclear decommissioning funding

H2A data sheet (probably incorrectly) uses "process water."

From H2A: Nuclear Fuel Cycle Cost of 6.85/MWh - based on U308 @ 315/lb. Enrich @ 625/SWU

0.5% of DepreciableCapital

Given without explanation in H2A

Each row corresponds to a technology sheet. Building one of the current sheet will decrease the cost of every technology listed by the corresponding "factor." The numbers in the first three columns are the 1st, 2nd and 4th numbers of the technology to-be-cheapered's IClass var

Building an upper-bound FC ought to decrease the cost of a normal FC by the same amount. You would probably want a similar LearningFactor (maybe even a reference) on the normal FC sheet

0	Variable	[Units]	(y-axis,x-axis)	Data	Source Used
VarData	IClass			[1,6,1,2]	
VarData	OClass			[2,1,-1]	
VarData	CYStart	[Year]		2025	
VarData	CYStop	[Year]		2050	
Axis	CY	CY		[2025,2050]	
VarData	IRR	[%]		10%	13
VarData	DepreciationLength	[Years]		20	13
VarData	AnalysisPeriod	[Years]		20	
VarData	Life	[Years]		40	13
Axis	PY	PY		[1,40]	
VarData	DesignCapacity	[kgH2/day]		719,395	13
VarData	DesignCapacity	[kgH2/year]		262,579,175	
VarData	CapacityFactor	[% of DesignCapacity]		90%	13
VarData	Location			1	
	DepreciableCapital		(Component)		
			Reactor and Power Conversion System	\$1,662,840,000.00	13
			Process Heat Transfer Loop	\$68,016,175.64	13
			Steam Electrolysis Plant	\$410,911,200.00	13
VarLinear	DepreciableCapital	[\$]	(CY)	2025 2050	
Data				\$2,141,767,375.64 \$2,141,767,375.64	
VarData	LandRequired	[acres]		400	
	FixedOM		(Component)		
			FTEs	384	13
			Labor Costs	\$50.00	13
			Labor Costs	\$39,936,000.00	13
			Overhead and G&A	20%	13
			Property Tax & Insurance	2%	13
			Rent	\$0.00	
			Lic., Permits and Fees	\$0.00	
			Matl for Maint. & Repairs	\$27,557,300.00	13
			Other Fees	\$0.00	13
			Other Fixed O&M Costs	\$1,650,000.00	13
VarLinear	FixedOM	[\$/year]	(PY,CY)	2025 2050	
Data				1 \$119,965,847.51 \$119,965,847.51	
End				40 \$119,965,847.51 \$119,965,847.51	
VarLinear	OtherFixed	[\$/year]	(PY,CY)	2025 2050	
Data				1 \$0.00 \$0.00	
End				40 \$0.00 \$0.00	
VarLinear	FeedstockEfficiency		(Feedstock,CY)	2025 2050	
Data					
		[GJH2/GJFeedstock]	Commercial Natural Gas	0.0000 0.0000	
		[GJH2/GJFeedstock]	Industrial Natural Gas	0.0000 0.0000	
		[GJH2/GJFeedstock]	Electric Utility Natural Gas	0.0000 0.0000	
		[GJH2/GJ]	Commercial Electricity	0.0000 0.0000	
		[GJH2/GJ]	Industrial Electricity	0.0000 0.0000	
		[GJH2/GJFeedstock]	Jillity Steam Coal (Central)	0.0000 0.0000	
		[GJH2/GJFeedstock]	Diesel Fuel	0.0000 0.0000	
		[GJH2/GJFeedstock]	Biomass	0.0000 0.0000	
		[GJH2/GJFeedstock]	Ethanol	0.0000 0.0000	
		[GJH2/GJFeedstock]	Methanol	0.0000 0.0000	
		[GJH2/GJFeedstock]	Gasoline	0.0000 0.0000	
		[GJH2/GJFeedstock]	Steam	0.0000 0.0000	
		[GJH2/L]	Cooling Water	0.0000 0.0000	
		[GJH2/L]	Demineralized Water	0.0109 0.0109	13
		[GJH2/L]	Process Water	0.0000 0.0000	
		[GJH2/Barel]	Bio-oil	0.0000 0.0000	
		[GJH2/GJFeedstock]	ility Steam Coal (Regional)	0.0000 0.0000	
		[GJH2/GJFeedstock]	MSW (1)	0.0000 0.0000	
End		[GJH2/GJFeedstock]	MSW (2)	0.0000 0.0000	
	OtherVariableOM		(Component)		
			WT Costs	\$0.00	
			SWD Costs	\$0.00	
			Other Variable Op. Costs	\$84,076,553.49	13
			Royalties	\$0.00	
			Operator Profit	\$0.00	
			Subsidies, Tax Incentives	\$0.00	
			CO2 Separation & Seq.	\$0.00	
VarLinear	OtherVariableOM	[\$/kgH2]	(PY,CY)	2025 2050	
Data				1 \$0.3558 \$0.3558	
End				40 \$0.3558 \$0.3558	
VarLinear	ByproductEfficiency		(Byproduct,CY)	2025 2050	
Data					
		[GJH2/GJ]	Byproduct Electricity	0.0000 0.0000	
		[GJH2/GJFeedstock]	Steam	0.0000 0.0000	
VarLinear	Emissions	[kg/kgH2]	(Species,CY)	2025 2050	
Data					
			Carbon	0 0	0.5% of DepreciableCapital
			GHG Equivalents	0 0	
			NOX	0 0	
			SOX	0 0	
			Particulates (PM10)	0 0	
			Mercury	0 0	
End					
VarLinear	ReplacementCosts	[\$]	(PY,CY)	2025 2050	
Data					
				1 \$10,708,836.88 \$10,708,836.88	13
				9 \$10,708,836.88 \$10,708,836.88	13
				10 \$134,692,636.88 \$134,692,636.88	13
				11 \$10,708,836.88 \$10,708,836.88	13
				19 \$10,708,836.88 \$10,708,836.88	13
				20 \$134,692,636.88 \$134,692,636.88	13
				21 \$10,708,836.88 \$10,708,836.88	13
				29 \$10,708,836.88 \$10,708,836.88	13
				30 \$134,692,636.88 \$134,692,636.88	13
				31 \$10,708,836.88 \$10,708,836.88	13
				40 \$10,708,836.88 \$10,708,836.88	13
End					
Var	LearningFactor		(Technology, Factor)	IClass[1] (I) IClass[2] (J) IClass[4] (L) Factor	
Data				FC.NG-SMR,1.5 (UPPER) 1 5 3 1	
End				FC.NG-SMR,1.5 1 5 2 1	
VarData	InitialUnitNo	[unit # in CYBegin]		500	
VarData	LearningFactorStart			1	

Plant Description
The systems examined are based on the application of an advanced HTGR plant (4 x 500MW modules) providing high efficiency electric power and high temperature (steam) to a central high temperature electrolysis (HTE) plant. HTE operation and performance is modeled on the design being developed by INL including published pilot-scale plant parameters (Refs 3-5).

Julie_perez:
Installed Cost. Overall installation cost factor is about 20% of uninstalled costs.

Julie_perez:
Installed Cost. Overall installation cost factor is about 20% of uninstalled costs.

Julie_perez:
Installed Cost. Overall installation cost factor is about 20% of uninstalled costs.

Nuclear decommissioning funding

From HGA:
Nuclear Fuel Cycle Cost of 9.3\$/MWh - based on U308 @ 35\$/lb, Enrich @ 55\$/SWU

0.5% of DepreciableCapital

Assumed refurbishment of electrolyzers every 10yr at 30% of initial plant cost.

Each row corresponds to a technology sheet. Building one of the current sheet will decrease the cost of every technology listed by the corresponding "factor." The numbers in the first three columns are the 1st, 2nd and 4th numbers of the technology to-be-changed's IClass var

All delivery (1-3) sheets with the same J share a LearningFactor (e.g., LT to 0.1TPD and LT to 1.5TPD only need one LearningFactor, since both sheets represent the same underlying technology - LTs). The L for this common factor should always be 1, and the factor should appear on every sheet that shares J.

Building an upper-bound FC ought to decrease the cost of a normal FC by the same amount. You would probably want a similar LearningFactor (maybe even a reference) on the normal FC sheet

0	Variable	(Units)	(y-axis,x-axis)	Data	Source Used
VarData	IClass			[1,6,1,3]	
VarData	OClass			[2,1,-1]	
VarData	CYStart	[Year]		2025	
VarData	CYStop	[Year]		2050	
Axis	CY	CY		[2025,2050]	
VarData	IRR	[%]		10%	12
VarData	DepreciationLength	[Years]		20	12
VarData	AnalysisPeriod	[Years]		20	
VarData	Life	[Years]		40	12
Axis	PY	PY		[1,40]	
VarData	DesignCapacity	[kgH2/day]		767.783	12
VarData	DesignCapacity	[kgH2/year]		280,240,710	
VarData	CapacityFactor	[% of DesignCapacity]		90%	12
VarData	Location			1	
VarLinear	DepreciableCapital	[\$]	(CY)	2025 2050 \$1,856,929,726.80 \$1,856,929,726.80	See H2A for breakdown. Includes installation factor.
Data	LandRequired	[acres]		400	12
VarLinear	FixedOM		(Component)		
Data					
End					
VarLinear	OtherFixed	[\$/year]	(PY,CY)	2025 2050 \$0.00 \$0.00	
Data					
End					
VarLinear	FeedstockEfficiency		(Feedstock,CY)	2025 2050 \$0.00 \$0.00	
Data					
End					
VarLinear	OtherVariableOM		(Component)		
Data					
End					
VarLinear	OtherVariableOM	[\$/kgH2]	(PY,CY)	2025 2050 \$0.3334 \$0.3334	
Data					
End					
VarLinear	ByproductEfficiency		(Byproduct,CY)	2025 2050 0.0000 0.0000	
Data					
End					
VarLinear	Emissions	[kg/kgH2]	(Species,CY)	2025 2050 0.0000 0.0000	
Data					
End					
VarLinear	ReplacementCosts	[\$]	(PY,CY)	2025 2050 \$9,284,648.63 \$9,284,648.63	
Data					
End					
Var	LearningFactor		(Technology,Factor)	IClass[1] (I) IClass[2] (J) IClass[4] (L) Factor	
Data					
End					
VarData	InitialUnitNo	[unit # in CYBegin]		500	
VarData	LearningFactorStart			1	

Plant Description
The systems examined are based on the application of an advanced H2ER plant (4 x 600MWt modules) providing direct process heat to a central 5-t water splitting process plant.

From H2A:
Nuclear Fuel Cycle Cost of 9.3\$/Mweh - based on U3O8 @38\$/lb, Enrich @ \$55\$/SWU

0.5% of DepreciableCapital

Intermediate Heat Exchangers, Replacement

All delivery (I=3) sheets with the same J share a LearningFactor (e.g., LT to 0.1TPD and LT to 1.5TPD only need one LearningFactor, since both sheets represent the same underlying technology - L15). The L for this common factor should always be 1, and the factor should appear on every sheet that shares it.

Each row corresponds to a technology sheet. Building one of the current sheet will decrease the cost of every technology listed by the corresponding "Factor." The numbers in the first three columns are the 1st, 2nd and 4th numbers of the technology to-be-cheapered's IClass var

Building an upper-bound FC ought to decrease the cost of a normal FC by the same amount. You would probably want a similar LearningFactor (maybe even a reference) on the normal FC sheet

Variable	[Units]	(y-axis,x-axis)	Data	Source Used																																																																																																																		
VarData	IClass		[1,7,1,1]																																																																																																																			
VarData	OClass		[2,1,-1]																																																																																																																			
VarData	CYStart	[Year]	2005																																																																																																																			
VarData	CYStop	[Year]	2050																																																																																																																			
Axis	CY	CY	2005-2050																																																																																																																			
VarData	IRR	[%]	10%	15																																																																																																																		
VarData	DepreciationLength	[Years]	20	15																																																																																																																		
VarData	AnalysisPeriod	[Years]	20																																																																																																																			
VarData	Life	[Years]	40	15																																																																																																																		
Axis	PY		[1-40]																																																																																																																			
VarData	DesignCapacity	[kgH2/day]	155,236	15																																																																																																																		
VarData	DesignCapacity	[kgH2/year]	56,661,070																																																																																																																			
VarData	CapacityFactor	[% of DesignCapacity]	90%	15																																																																																																																		
VarData	Location		5																																																																																																																			
Plant Description The systems examined are based on the Battelle/FERCO indirectly-heated biomass gasifier, conventional catalytic steam reforming, water gas shift, and pressure swing adsorption 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.																																																																																																																						
DepreciableCapital (Direct) <table><tr><th>(Component)</th><th>Uninstalled Costs</th><th>Installation Factor</th><th>Installed Costs</th></tr><tr><td>Feed Handling & Drying</td><td>\$7,651,821.86</td><td>247%</td><td>\$18,900,000.00</td></tr><tr><td>Gasification, Tar Reforming & Quench</td><td>\$6,801,619.43</td><td>247%</td><td>\$16,800,000.00</td></tr><tr><td>Compression & Sulfur Removal</td><td>\$6,315,789.47</td><td>247%</td><td>\$15,600,000.00</td></tr><tr><td>Steam Methane Reforming, Shift and PSA</td><td>\$12,267,206.48</td><td>247%</td><td>\$30,300,000.00</td></tr><tr><td>Hydrogen Compression</td><td>\$1,052,631.58</td><td>247%</td><td>\$2,600,000.00</td></tr><tr><td>Steam System and Power Generation</td><td>\$5,829,959.51</td><td>247%</td><td>\$14,400,000.00</td></tr><tr><td>Cooling Water and Other Utilities</td><td>\$1,376,518.22</td><td>247%</td><td>\$3,400,000.00</td></tr><tr><td>Buildings & Structures</td><td></td><td></td><td>\$6,000,000.00</td></tr></table>				(Component)	Uninstalled Costs	Installation Factor	Installed Costs	Feed Handling & Drying	\$7,651,821.86	247%	\$18,900,000.00	Gasification, Tar Reforming & Quench	\$6,801,619.43	247%	\$16,800,000.00	Compression & Sulfur Removal	\$6,315,789.47	247%	\$15,600,000.00	Steam Methane Reforming, Shift and PSA	\$12,267,206.48	247%	\$30,300,000.00	Hydrogen Compression	\$1,052,631.58	247%	\$2,600,000.00	Steam System and Power Generation	\$5,829,959.51	247%	\$14,400,000.00	Cooling Water and Other Utilities	\$1,376,518.22	247%	\$3,400,000.00	Buildings & Structures			\$6,000,000.00	15 15 15 15 15 15 15																																																																														
(Component)	Uninstalled Costs	Installation Factor	Installed Costs																																																																																																																			
Feed Handling & Drying	\$7,651,821.86	247%	\$18,900,000.00																																																																																																																			
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Steam Methane Reforming, Shift and PSA	\$12,267,206.48	247%	\$30,300,000.00																																																																																																																			
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Steam System and Power Generation	\$5,829,959.51	247%	\$14,400,000.00																																																																																																																			
Cooling Water and Other Utilities	\$1,376,518.22	247%	\$3,400,000.00																																																																																																																			
Buildings & Structures			\$6,000,000.00																																																																																																																			
DepreciableCapital (Direct) <table><tr><th>(Component,CY)</th><th>2005</th><th>2015</th><th>2025</th></tr><tr><td>Cost Factor</td><td>100%</td><td>88%</td><td>75%</td></tr><tr><td>Uninstalled Costs</td><td>\$41,295,546.56</td><td>\$37,149,797.57</td><td>\$32,644,529.26</td></tr><tr><td>Installed Costs</td><td>\$108,000,000.00</td><td>\$97,474,285.71</td><td>\$85,915,178.57</td></tr></table>				(Component,CY)	2005	2015	2025	Cost Factor	100%	88%	75%	Uninstalled Costs	\$41,295,546.56	\$37,149,797.57	\$32,644,529.26	Installed Costs	\$108,000,000.00	\$97,474,285.71	\$85,915,178.57	15 2005: 15 2015: 16 2025: 17																																																																																																		
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DepreciableCapital (Indirect) <table><tr><th>(Component,CY)</th><th>2005</th><th>2015</th><th>2025</th></tr><tr><td>Site Preparation</td><td>1%</td><td>1%</td><td>1%</td></tr><tr><td>Engineering & Design</td><td>13%</td><td>13%</td><td>13%</td></tr><tr><td>Process Contingency</td><td>\$0.00</td><td>\$0.00</td><td>\$0.00</td></tr><tr><td>Project Contingency</td><td>15%</td><td>25%</td><td>25%</td></tr><tr><td>Other Depreciable Capital</td><td>\$0.00</td><td>\$0.00</td><td>\$0.00</td></tr><tr><td>One-Time Licensing Fees</td><td>\$0.00</td><td>\$0.00</td><td>\$0.00</td></tr><tr><td>Up-Front Permitting Costs</td><td>9%</td><td>9%</td><td>9%</td></tr></table>				(Component,CY)	2005	2015	2025	Site Preparation	1%	1%	1%	Engineering & Design	13%	13%	13%	Process Contingency	\$0.00	\$0.00	\$0.00	Project Contingency	15%	25%	25%	Other Depreciable Capital	\$0.00	\$0.00	\$0.00	One-Time Licensing Fees	\$0.00	\$0.00	\$0.00	Up-Front Permitting Costs	9%	9%	9%	15 15 2005: 15 2015: 16 2025: 17																																																																																		
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Var.Linear	DepreciableCapital	[\$]	(CY)	2005 2015 2025 2050																																																																																																																		
Data				\$142,369,554.66 \$138,229,494.04 \$121,824,405.36 \$121,824,405.36																																																																																																																		
VarData	LandRequired	[acres]		50																																																																																																																		
FixedOM <table><tr><th>(Component)</th><th>2005</th><th>2015</th><th>2025</th><th>2050</th></tr><tr><td>FTEs</td><td>54</td><td></td><td></td><td></td></tr><tr><td>Labor Costs</td><td>\$50.00</td><td></td><td></td><td></td></tr><tr><td>Labor Costs</td><td>\$5,616,000.00</td><td></td><td></td><td></td></tr><tr><td>Overhead and G&A</td><td>20%</td><td></td><td></td><td></td></tr><tr><td>Property Tax & Insurance</td><td>2%</td><td></td><td></td><td></td></tr><tr><td>Rent</td><td>\$0.00</td><td></td><td></td><td></td></tr><tr><td>Lic., Permits and Fees</td><td>\$0.00</td><td></td><td></td><td></td></tr><tr><td>Mat'l for Maint. & Repairs</td><td>0.5%</td><td></td><td></td><td></td></tr><tr><td>Other Fees</td><td>\$0.00</td><td></td><td></td><td></td></tr><tr><td>Other Fixed O&M Costs</td><td>\$0.00</td><td></td><td></td><td></td></tr></table>				(Component)	2005	2015	2025	2050	FTEs	54				Labor Costs	\$50.00				Labor Costs	\$5,616,000.00				Overhead and G&A	20%				Property Tax & Insurance	2%				Rent	\$0.00				Lic., Permits and Fees	\$0.00				Mat'l for Maint. & Repairs	0.5%				Other Fees	\$0.00				Other Fixed O&M Costs	\$0.00				15 15 15 15 15 15 15																																																											
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Other Fixed O&M Costs	\$0.00																																																																																																																					
Var.Linear	FixedOM	[\$/year]	(PY,CY)	2005 2015 2025 2050																																																																																																																		
Data				\$10,126,591.09 \$9,991,161.31 \$9,605,264.00 \$9,605,264.00																																																																																																																		
Var.Linear	OtherFixed	[\$/year]	(PY,CY)	2005 2050																																																																																																																		
Data				\$7,000,000.00 \$7,000,000.00																																																																																																																		
Var.Linear	FeedstockEfficiency		(Feedstock,CY)	2005 2015 2025 2050																																																																																																																		
Data																																																																																																																						
<table><tr><td>[GJ_{H2}/GJFeedstock]</td><td>Commercial Natural Gas</td><td>19.5126</td><td>22.9560</td><td>39.0252</td><td>39.0252</td></tr><tr><td>[GJ_{H2}/GJFeedstock]</td><td>Industrial Natural Gas</td><td>0.0000</td><td>0.0000</td><td>0.0000</td><td>0.0000</td></tr><tr><td>[GJ_{H2}/GJFeedstock]</td><td>Electric Utility Natural Gas</td><td>0.0000</td><td>0.0000</td><td>0.0000</td><td>0.0000</td></tr><tr><td>[GJ_{H2}/GJ]</td><td>Commercial Electricity</td><td>0.0000</td><td>0.0000</td><td>0.0000</td><td>0.0000</td></tr><tr><td>[GJ_{H2}/GJ]</td><td>Industrial Electricity</td><td>21.3559</td><td>35.5931</td><td>35.5931</td><td>35.5931</td></tr><tr><td>[GJ_{H2}/GJFeedstock]</td><td>Utility Steam Coal (Central)</td><td>0.0000</td><td>0.0000</td><td>0.0000</td><td>0.0000</td></tr><tr><td>[GJ_{H2}/GJFeedstock]</td><td>Diesel Fuel</td><td>0.0000</td><td>0.0000</td><td>0.0000</td><td>0.0000</td></tr><tr><td>[GJ_{H2}/GJFeedstock]</td><td>Biomass</td><td>0.4500</td><td>0.5140</td><td>0.5490</td><td>0.5490</td></tr><tr><td>[GJ_{H2}/GJFeedstock]</td><td>Ethanol</td><td>0.0000</td><td>0.0000</td><td>0.0000</td><td>0.0000</td></tr><tr><td>[GJ_{H2}/GJFeedstock]</td><td>Methanol</td><td>0.0000</td><td>0.0000</td><td>0.0000</td><td>0.0000</td></tr><tr><td>[GJ_{H2}/GJFeedstock]</td><td>Gasoline</td><td>0.0000</td><td>0.0000</td><td>0.0000</td><td>0.0000</td></tr><tr><td>[GJ_{H2}/GJFeedstock]</td><td>Steam</td><td>0.0000</td><td>0.0000</td><td>0.0000</td><td>0.0000</td></tr><tr><td>[GJ_{H2}/L]</td><td>Cooling Water</td><td>0.0004</td><td>0.0004</td><td>0.0004</td><td>0.0004</td></tr><tr><td>[GJ_{H2}/L]</td><td>Demineralized Water</td><td>0.0000</td><td>0.0000</td><td>0.0000</td><td>0.0000</td></tr><tr><td>[GJ_{H2}/L]</td><td>Process Water</td><td>0.0243</td><td>0.0243</td><td>0.0243</td><td>0.0243</td></tr><tr><td>[GJ_{H2}/Barrel]</td><td>Bio-oil</td><td>0.0000</td><td>0.0000</td><td>0.0000</td><td>0.0000</td></tr><tr><td>[GJ_{H2}/GJFeedstock]</td><td>Utility Steam Coal (Regional)</td><td>0.0000</td><td>0.0000</td><td>0.0000</td><td>0.0000</td></tr><tr><td>[GJ_{H2}/GJFeedstock]</td><td>MSW (1)</td><td>0.0000</td><td>0.0000</td><td>0.0000</td><td>0.0000</td></tr><tr><td>[GJ_{H2}/GJFeedstock]</td><td>MSW (2)</td><td>0.0000</td><td>0.0000</td><td>0.0000</td><td>0.0000</td></tr></table>				[GJ _{H2} /GJFeedstock]	Commercial Natural Gas	19.5126	22.9560	39.0252	39.0252	[GJ _{H2} /GJFeedstock]	Industrial Natural Gas	0.0000	0.0000	0.0000	0.0000	[GJ _{H2} /GJFeedstock]	Electric Utility Natural Gas	0.0000	0.0000	0.0000	0.0000	[GJ _{H2} /GJ]	Commercial Electricity	0.0000	0.0000	0.0000	0.0000	[GJ _{H2} /GJ]	Industrial Electricity	21.3559	35.5931	35.5931	35.5931	[GJ _{H2} /GJFeedstock]	Utility Steam Coal (Central)	0.0000	0.0000	0.0000	0.0000	[GJ _{H2} /GJFeedstock]	Diesel Fuel	0.0000	0.0000	0.0000	0.0000	[GJ _{H2} /GJFeedstock]	Biomass	0.4500	0.5140	0.5490	0.5490	[GJ _{H2} /GJFeedstock]	Ethanol	0.0000	0.0000	0.0000	0.0000	[GJ _{H2} /GJFeedstock]	Methanol	0.0000	0.0000	0.0000	0.0000	[GJ _{H2} /GJFeedstock]	Gasoline	0.0000	0.0000	0.0000	0.0000	[GJ _{H2} /GJFeedstock]	Steam	0.0000	0.0000	0.0000	0.0000	[GJ _{H2} /L]	Cooling Water	0.0004	0.0004	0.0004	0.0004	[GJ _{H2} /L]	Demineralized Water	0.0000	0.0000	0.0000	0.0000	[GJ _{H2} /L]	Process Water	0.0243	0.0243	0.0243	0.0243	[GJ _{H2} /Barrel]	Bio-oil	0.0000	0.0000	0.0000	0.0000	[GJ _{H2} /GJFeedstock]	Utility Steam Coal (Regional)	0.0000	0.0000	0.0000	0.0000	[GJ _{H2} /GJFeedstock]	MSW (1)	0.0000	0.0000	0.0000	0.0000	[GJ _{H2} /GJFeedstock]	MSW (2)	0.0000	0.0000	0.0000	0.0000	2005: 15 2015: 16 2025: 17 2005: 15 2015: 16 2025: 17 2005: 15 2015: 16 2025: 17
[GJ _{H2} /GJFeedstock]	Commercial Natural Gas	19.5126	22.9560	39.0252	39.0252																																																																																																																	
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[GJ _{H2} /GJFeedstock]	Electric Utility Natural Gas	0.0000	0.0000	0.0000	0.0000																																																																																																																	
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[GJ _{H2} /GJFeedstock]	Diesel Fuel	0.0000	0.0000	0.0000	0.0000																																																																																																																	
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[GJ _{H2} /GJFeedstock]	Ethanol	0.0000	0.0000	0.0000	0.0000																																																																																																																	
[GJ _{H2} /GJFeedstock]	Methanol	0.0000	0.0000	0.0000	0.0000																																																																																																																	
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[GJ _{H2} /GJFeedstock]	Steam	0.0000	0.0000	0.0000	0.0000																																																																																																																	
[GJ _{H2} /L]	Cooling Water	0.0004	0.0004	0.0004	0.0004																																																																																																																	
[GJ _{H2} /L]	Demineralized Water	0.0000	0.0000	0.0000	0.0000																																																																																																																	
[GJ _{H2} /L]	Process Water	0.0243	0.0243	0.0243	0.0243																																																																																																																	
[GJ _{H2} /Barrel]	Bio-oil	0.0000	0.0000	0.0000	0.0000																																																																																																																	
[GJ _{H2} /GJFeedstock]	Utility Steam Coal (Regional)	0.0000	0.0000	0.0000	0.0000																																																																																																																	
[GJ _{H2} /GJFeedstock]	MSW (1)	0.0000	0.0000	0.0000	0.0000																																																																																																																	
[GJ _{H2} /GJFeedstock]	MSW (2)	0.0000	0.0000	0.0000	0.0000																																																																																																																	
OtherVariableOM <table><tr><td>WT Costs</td><td>\$1,200,000.00</td><td></td><td></td><td></td></tr><tr><td>SWD Costs</td><td>\$730,000.00</td><td></td><td></td><td></td></tr><tr><td>Other Variable Op. Costs</td><td>\$130,000.00</td><td></td><td></td><td></td></tr><tr><td>Royalties</td><td>\$0.00</td><td></td><td></td><td></td></tr><tr><td>Operator Profit</td><td>\$0.00</td><td></td><td></td><td></td></tr><tr><td>Subsidies, Tax Incentives</td><td>\$0.00</td><td></td><td></td><td></td></tr><tr><td>CO2 Separation & Sec.</td><td>\$0.00</td><td></td><td></td><td></td></tr></table>				WT Costs	\$1,200,000.00				SWD Costs	\$730,000.00				Other Variable Op. Costs	\$130,000.00				Royalties	\$0.00				Operator Profit	\$0.00				Subsidies, Tax Incentives	\$0.00				CO2 Separation & Sec.	\$0.00				15 15 15																																																																															
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CO2 Separation & Sec.	\$0.00																																																																																																																					
Var.Linear	OtherVariableOM	[\$/kgH2]	(PY,CY)	2005 2050																																																																																																																		
Data				\$0.0404 \$0.0404																																																																																																																		
Var.Linear	ByproductEfficiency		(Byproduct,CY)	2005 2050																																																																																																																		
Data				0.0000 0.0000																																																																																																																		
Var.Linear	Emissions	[kg/kgH2]	(Species,CY)	2005 2015 2025 2050																																																																																																																		
Data																																																																																																																						
<table><tr><td>GHG Equivalents</td><td>0.019853181</td><td>0.016875204</td><td>0.009926591</td><td>0.009926591</td></tr><tr><td>NOX</td><td>0</td><td>0</td><td>0</td><td>0</td></tr><tr><td>SOX</td><td>0</td><td>0</td><td>0</td><td>0</td></tr><tr><td>Particulates (PM10)</td><td>0</td><td>0</td><td>0</td><td>0</td></tr><tr><td>Mercury</td><td>0</td><td>0</td><td>0</td><td>0</td></tr></table>				GHG Equivalents	0.019853181	0.016875204	0.009926591	0.009926591	NOX	0	0	0	0	SOX	0	0	0	0	Particulates (PM10)	0	0	0	0	Mercury	0	0	0	0																																																																																										
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Particulates (PM10)	0	0	0	0																																																																																																																		
Mercury	0	0	0	0																																																																																																																		
Var.Linear	ReplacementCosts	[\$]	(PY,CY)	2005 2015 2025 2050																																																																																																																		
Data																																																																																																																						
Var	LearningFactor		(Technology,Factor)	2005 2015 2025 2050																																																																																																																		
Data																																																																																																																						
VarData	InitialUnitNo	[unit # in CYBegin]		500																																																																																																																		
VarData	LearningFactorStart			1																																																																																																																		
Building an upper-bound FC ought to decrease the cost of a normal FC by the same amount. You would probably want a similar Learning factor (maybe even a reference) on the normal FC sheet																																																																																																																						

0	Variable	[Units]	(y-axis,x-axis)	Data	Source Used
VarData	IClass			[1,7,1,2]	
VarData	OClass			[2,3,3]	
VarData	CYStart	[Year]		2005	
VarData	CYStop	[Year]		2050	
Axis	CY	CY		2005-2050	
VarData	IRR	[%]		10%	15
VarData	DepreciationLength	[Years]		20	15
VarData	AnalysisPeriod	[Years]		20	
VarData	Life	[Years]		40	15
Axis	PY	PY		[1-40]	
VarData	DesignCapacity	[kgH2/day]		155,236	15
VarData	CapacityFactor	[kgH2/year]		56,661,070	15
VarData	Location			5	15
VarData	DepreciableCapital (Direct)	(Component)		Uninstalled Costs Installation Factor Installed Costs	
	Feed Handling & Drying			\$7,651,821.86 247% \$18,900,000.00	15
	Gasification, Tar Reforming & Quench			\$6,801,619.43 247% \$16,800,000.00	15
	Compression & Sulfur Removal			\$6,315,789.47 247% \$15,600,000.00	15
	Steam Methane Reforming, Shift and PSA			\$12,267,206.48 247% \$30,300,000.00	15
	Hydrogen Compression			\$1,052,631.58 247% \$2,600,000.00	15
	Steam System and Power Generation			\$5,629,959.51 247% \$14,400,000.00	15
	Cooling Water and Other Utilities			\$1,376,518.22 247% \$3,400,000.00	15
	Buildings & Structures			\$6,000,000.00	15
VarData	DepreciableCapital (Indirect)	(Component,CY)		2005 2015 2025	2005: 15 2015: 16 2025: 17
	Cost Factor			100% 88% 75%	
	Uninstalled Costs			\$41,295,546.56 \$37,149,797.57 \$35,644,569.36	
	Installed Costs			\$108,000,000.00 \$97,474,285.71 \$85,915,178.57	
	(Component,CY)			2005 2015 2025	
	Site Preparation			1% 1% 1%	15
	Engineering & Design			13% 13% 13%	15
	Process Contingency			\$0.00 \$0.00 \$0.00	
	Project Contingency			15% 25% 25%	2005: 15 2015: 16 2025: 17
	Other Depreciable Capital			\$0.00 \$0.00 \$0.00	
	One-Time Licensing Fees			\$0.00 \$0.00 \$0.00	
	Up-Front Permitting Costs			9% 9% 9%	15
VarLinear	DepreciableCapital	(\$)	(CY)	2005 2015 2025 2050	2005: 15 2015: 16 2025: 17
Data	LandRequired	[acres]		\$142,369,554.66 \$138,229,494.04 \$121,824,405.36 \$121,824,405.36	15
VarData	FixedOM	(Component)		2005 2015 2025 2050	
	FTEs			54	15
	Labor Costs			\$5,616,000.00	15
	Overhead and G&A			20%	15
	Property Tax & Insurance			2%	15
	Rent			\$0.00	15
	Lic, Permits and Fees			\$0.00	15
	Matl for Maint. & Repairs			0.5%	15
	Other Fees			\$0.00	15
	Other Fixed O&M Costs			\$0.00	15
VarLinear	FixedOM	(\$/year)	(PY,CY)	2005 2015 2025 2050	2005: 15 2015: 16 2025: 17
Data	OtherFixed	(\$/year)	(PY,CY)	2005 2015 2025 2050	2005: 15 2015: 16 2025: 17
VarLinear	FeedstockEfficiency	(Feedstock,CY)		2005 2015 2025 2050	2005: 15 2015: 16 2025: 17
	Commercial Natural Gas			19.5126 22.9560 39.0252 39.0252	2005: 15 2015: 16 2025: 17
	Industrial Natural Gas			0.0000 0.0000 0.0000 0.0000	
	Electric Utility Natural Gas			0.0000 0.0000 0.0000 0.0000	
	Commercial Electricity			0.0000 0.0000 0.0000 0.0000	
	Industrial Electricity			21.3559 35.5931 35.5931 35.5931	2005: 15 2015: 16 2025: 17
	Utility Steam Coal (Central)			0.0000 0.0000 0.0000 0.0000	
	Diesel Fuel			0.0000 0.0000 0.0000 0.0000	2005: 15 2015: 16 2025: 17
	Biomass			0.4500 0.5140 0.5490 0.5490	
	Ethanol			0.0000 0.0000 0.0000 0.0000	
	Methanol			0.0000 0.0000 0.0000 0.0000	
	Gasoline			0.0000 0.0000 0.0000 0.0000	
	Steam			0.0000 0.0000 0.0000 0.0000	
	Cooling Water			0.0004 0.0004 0.0004 0.0004	2005: 15 2015: 16 2025: 17
	Deminerlized Water			0.0000 0.0000 0.0000 0.0000	2005: 15 2015: 16 2025: 17
	Process Water			0.0243 0.0243 0.0243 0.0243	
	Bio-oil			0.0000 0.0000 0.0000 0.0000	
	Utility Steam Coal (Regional)			0.0000 0.0000 0.0000 0.0000	
	MSW (1)			0.0000 0.0000 0.0000 0.0000	
	MSW (2)			0.0000 0.0000 0.0000 0.0000	
End	OtherVariableOM	(Component)		WT Costs \$1,200,000.00 SWD Costs \$730,000.00 Other Variable Op. Costs \$130,000.00 Royalties \$0.00 Operator Profit \$0.00 Subsidies, Tax Incentives \$0.00 CO2 Separation & Seq. \$0.00	15 15 15
VarLinear	OtherVariableOM	(\$/kgH2)	(PY,CY)	2005 2015 2050	2005: 15 2015: 16 2025: 17
Data	ByproductEfficiency	(Byproduct,CY)		2005 2015 2050	2005: 15 2015: 16 2025: 17
	Byproduct Electricity			0.0000 0.0000	
	Steam			0.0000 0.0000	
VarLinear	Emissions	[kg/kgH2]	(Species,CY)	2005 2015 2025 2050	2005: 15 2015: 16 2025: 17
	Carbon			0.019853181 0.016875204 0.009926591 0.009926591	
	GHG Equivalents			0 0 0 0	
	NOX			0 0 0 0	
	SOX			0 0 0 0	
	Particulates (PM10)			0 0 0 0	
	Mercury			0 0 0 0	
End	ReplacementCosts	(\$)	(PY,CY)	2005 2015 2025 2050	2005: 15 2015: 16 2025: 17
	FC-NG-SMR, 1.5 (UPPER)			\$711,847.77 \$691,147.47 \$609,122.03 \$609,122.03	
	FC-NG-SMR, 1.5			\$711,847.77 \$691,147.47 \$609,122.03 \$609,122.03	
VarData	LearningFactor	(Technology,Factor)	(IClass[1] (I) IClass[2] (J) IClass[4] (L) Factor	1 5 3	2005: 15 2015: 16 2025: 17
VarData	InitialUnitNo	[unit # in CYBegin]		500	
VarData	LearningFactorStart			1	

Plant Description
The systems examined are based on the Battelle/PERCO indirectly-heated biomass gasifier, conventional catalytic steam reforming, water gas shift, and pressure swing adsorption 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.

Applies to Gasification, Tar Reforming, & Quench + Steam Methane Reforming, Shift, and PSA.

Applies to Gasification, Tar Reforming, & Quench + Steam Methane Reforming, Shift, and PSA.

Plant Capacity in H2A is 12% in 2025 than in 2005. To account for this we divide the capital cost by 1.12.

Plant Capacity in H2A is 5% in 2015 than in 2005. To account for this we divide the capital cost by 1.05.

Site Prep & Permitting Costs are % of Uninstalled Costs. This deviates from Reference 15 - 17. We believe Reference is in error.

Catalyst, olivine, other

Used stated efficiency from H2A's "Performance assumptions" tab. Computed assuming Poplar.

From H2A: Consists of MgO (\$0.01MM), boiler chemicals (\$0.03MM), #2 diesel fuel (\$0.08MM), cooling tower chemicals (\$0.01MM)

0.5% of DepreciableCapital

Each row corresponds to a technology sheet. Building one of the current sheet will decrease the cost of every technology listed by the corresponding "Factor." The numbers in the first three columns are the 1st, 2nd and 4th numbers of the technology to be cheapened's IClass var

All delivery (1-3) sheets with the same J share a LearningFactor (e.g., LT to 0.1TPD and LT to 1.5TPD only need one LearningFactor, since both sheets represent the same underlying technology - LTs). The L for this common factor should always be 1, and the factor should appear on every sheet that cheapens L

Building an upper-bound FC ought to decrease the cost of a normal FC by the same amount. You would probably want a similar LearningFactor (maybe even a reference) on the normal FC sheet

0	Variable	[Units]	(y-axis,x-axis)	Data	Source Used
VarData	IClass			[1,8,1,1]	
VarData	OClass			[2,1,-1]	
VarData	CYStart	[Year]		2012	5
VarData	CYStop	[Year]		2012	5
Axis	CY	CY		[2012:2012]	
VarData	IRR	[%]		10%	27
VarData	DepreciationLength	[Years]		20	27
VarData	AnalysisPeriod	[Years]		20	
VarData	Life	[Years]		40	27
Axis	PY	PY		[1:40]	
VarData	DesignCapacity	[kgH2/day]		80.000	50
VarData	DesignCapacity	[kgH2/year]		29,200.000	
VarData	CapacityFactor	[% of DesignCapacity]		100%	50
VarData	Location			2	
Var.Linear	DepreciableCapital	[\$]		2012 2013	
Data				\$0.00 \$0.00	
VarData	LandRequired	[acres]		0	
Var.Linear	FixedOM	[\$/year]		(PY,CY) 2012 2013	
Data				1 \$0.00 \$0.00	
End				40 \$0.00 \$0.00	
Var.Linear	OtherFixed	[\$/year]		(PY,CY) 2012 2013	
Data				1 \$0.00 \$0.00	
End				40 \$0.00 \$0.00	
Var.Linear	FeedstockEfficiency			(Feedstock,CY) 2012 2013	
Data					
	(GJH2/GJFeedstock)	Commercial Natural Gas		0.0000 0.0000	
	(GJH2/GJFeedstock)	Industrial Natural Gas		0.0000 0.0000	
	(GJH2/GJFeedstock)	Electric Utility Natural Gas		0.0000 0.0000	
	(GJH2/GJ)	Commercial Electricity		0.0000 0.0000	
	(GJH2/GJ)	Industrial Electricity		0.0000 0.0000	
	(GJH2/GJFeedstock)	Utility Steam Coal (Central)		0.0000 0.0000	
	(GJH2/GJFeedstock)	Diesel Fuel		0.0000 0.0000	
	(GJH2/GJFeedstock)	Biomass		0.0000 0.0000	
	(GJH2/GJFeedstock)	Ethanol		0.0000 0.0000	
	(GJH2/GJFeedstock)	Methanol		0.0000 0.0000	
	(GJH2/GJFeedstock)	Gasoline		0.0000 0.0000	
	(GJH2/GJFeedstock)	Steam		0.0000 0.0000	
	(GJH2/L)	Cooling Water		0.0000 0.0000	
	(GJH2/L)	Demineralized Water		0.0000 0.0000	
	(GJH2/L)	Process Water		0.0000 0.0000	
	(GJH2/Barrel)	Bio-oil		0.0000 0.0000	
	(GJH2/GJFeedstock)	Utility Steam Coal (Regional)		0.0000 0.0000	
	(GJH2/GJFeedstock)	MSW (1)		0.0000 0.0000	
	(GJH2/GJFeedstock)	MSW (2)		0.0000 0.0000	
End					
Var.Linear	OtherVariableOM	[\$/kgH2]		(PY,CY) 2012 2013	
Data				1 \$0.90 \$0.90	10
End				40 \$0.90 \$0.90	
Var.Linear	ByproductEfficiency			(Byproduct,CY) 2012 2013	
Data					
	(GJH2/GJ)	Byproduct Electricity		0.0000 0.0000	
End					
	(GJH2/GJFeedstock)	Steam		0.0000 0.0000	
Var.Linear	Emissions	[kg/kgH2]		(Species,CY) 2012	
Data					
		Carbon		0 0	19
		GHG Equivalents		0 0	
		NOX		0 0	
		SOX		0 0	
		Particulates (PM10)		0 0	
End					
		Mercury		0 0	
Var.Linear	ReplacementCosts	[\$]		(PY,CY) 2012 2013	
Data				1 \$0.00 \$0.00	
End				40 \$0.00 \$0.00	

Plant Description
Existing facility in the region of interest with surplus supply willing to provide this surplus at a lower variable cost.

Additional \$0.10/kg added to production costs.
Assumed cost of linking 4 x 20 TPD existing plants with 7 mi. pipe for each. Pressures were 25 Atm to 20 Atm, capital cost recovery factor 0.25.

Variable	[Units]	(y-axis,x-axis)	Data	Source Used			
VarData	IClass		[1,9,1,1]				
VarData	OClass		[2,1,-1]				
VarData	CYStart	[Year]	2005	49			
VarData	CYStop	[Year]	2050				
Axis	CY	CY	[2005:2050]				
VarData	IRR	[%]	10%	49			
VarData	DepreciationLength	[Years]	20	49			
VarData	AnalysisPeriod	[Years]	20				
VarData	Life	[Years]	40	49			
Axis	PY	PY	[1:40]				
VarData	DesignCapacity	[kgH2/day]	150,000	49			
VarData	DesignCapacity	[kgH2/year]	54,750,000				
VarData	CapacityFactor	[% of DesignCapacity]	90%	49			
VarData	Location		1				
VarData	DepreciableCapital (Direct)	(Component)	Uninstalled Costs	Installation Factor	Installed Costs		
			Feed Handling & Drying	\$6,000,000.00	250%	\$15,000,000.00	49
			Gasification, Tar Reforming & Quench	\$8,000,000.00	250%	\$20,000,000.00	49
			Compression & Sulfur Removal	\$6,000,000.00	250%	\$15,000,000.00	49
			Steam Methane Reforming, Shift and PSA	\$8,000,000.00	250%	\$20,000,000.00	49
			Hydrogen Compression	\$1,000,000.00	250%	\$2,500,000.00	49
			Steam System and Power Generation	\$6,000,000.00	250%	\$15,000,000.00	49
			Cooling Water and Other Utilities	\$1,500,000.00	250%	\$3,750,000.00	49
VarData	DepreciableCapital (Indirect)	(Component,CY)	2005	2015	2025		
			Cost Factor	100%	88%	75%	
			Uninstalled Costs	\$36,500,000.00	\$34,580,000.00	\$32,500,000.00	
			Installed Costs	\$91,250,000.00	\$86,450,000.00	\$81,250,000.00	
VarData	LandRequired	[acres]	50				49
VarData	FixedOM	(Component)	FTEs	\$4			15
			Labor Costs	\$50.00			15
			Labor Costs	\$5,616,000.00			
			Overhead and G&A	20%			15
			Property Tax & Insurance	2%			15
			Rent	\$0.00			
			Lic., Permits and Fees	\$0.00			
			Mart for Maint. & Repairs	1.5%			49
			Other Fees	\$0.00			
			Other Fixed O&M Costs	\$0.00			
VarLinear	FixedOM	(\$/year)	(PY,CY)	2005	2015	2025	2050
Data				\$10,626,450.00	\$10,200,450.00	\$10,200,450.00	\$10,200,450.00
End				\$10,626,450.00	\$0.00	\$10,200,450.00	\$10,200,450.00
VarLinear	OtherFixed	(\$/year)	(PY,CY)	2005	2050		
Data				\$7,000,000.00	\$7,000,000.00		
End				\$7,000,000.00	\$7,000,000.00		
VarLinear	FeedstockEfficiency		(Feedstock,CY)	2005	2015	2025	2050
			Commercial Natural Gas	19.5126	22.9560	39.0252	39.0252
			Industrial Natural Gas	0.0000	0.0000	0.0000	0.0000
			Electric Utility Natural Gas	0.0000	0.0000	0.0000	0.0000
			Commercial Electricity	0.0000	0.0000	0.0000	0.0000
			Industrial Electricity	21.3559	35.5931	35.5931	35.5931
			Electric Utility Steam Coal (Central)	0.0000	0.0000	0.0000	0.0000
			Diesel Fuel	0.0000	0.0000	0.0000	0.0000
			Biomass	0.0000	0.0000	0.0000	0.0000
			Ethanol	0.0000	0.0000	0.0000	0.0000
			Methanol	0.0000	0.0000	0.0000	0.0000
			Gasoline	0.0000	0.0000	0.0000	0.0000
			Steam	0.0000	0.0000	0.0000	0.0000
			Cooling Water	0.0004	0.0004	0.0004	0.0004
			Deminerlized Water	0.0000	0.0000	0.0000	0.0000
			Process Water	0.0243	0.0243	0.0243	0.0243
			Bio-oil	0.0000	0.0000	0.0000	0.0000
			Electric Utility Steam Coal (Regional)	0.0000	0.0000	0.0000	0.0000
			MSW (1)	0.6500	0.6500	0.6500	0.6500
			MSW (2)	0.0000	0.0000	0.0000	0.0000
End	OtherVariableOM	(Component)	WT Costs	\$0.00			
			SWD Costs	\$2,000,000.00			
			Other Variable Op. Costs	\$130,000.00			
			Royalties	\$0.00			
			Operator Profit	\$0.00			
			Subsidies, Tax Incentives	\$0.00			
			CO2 Separation & Seq.	\$0.00			
VarLinear	OtherVariableOM	(\$/kgH2)	(PY,CY)	2005	2050		
Data				\$0.0432	\$0.0432		
End				\$0.0432	\$0.0432		
VarLinear	ByproductEfficiency		(Byproduct,CY)	2005	2050		
Data				0.0000	0.0000		
End				0.0000	0.0000		
VarLinear	Emissions	[kg/kgH2]	(Species,CY)	2005	2015	2025	2050
			Carbon	0	0	0	0
			GHG Equivalents	0.019853181	0.016875204	0.009926591	0.009926591
			NOx	0	0	0	0
			SOx	0	0	0	0
			Particulates (PM10)	0	0	0	0
			Mercury	0	0	0	0
End	ReplacementCosts	(\$)	(PY,CY)	2005	2015	2025	2050
Data				\$629,625.00	\$596,505.00	\$560,625.00	\$560,625.00
End				\$629,625.00	\$596,505.00	\$560,625.00	\$560,625.00
Var	LearningFactor		(Technology,Factor)	1	5	3	1
Data				1	5	3	1
End				1	5	3	1
VarData	InitialUnitNo	[unit # in CYBegin]	500				
VarData	LearningFactorStart		1				

Plant Description
The system is modeled as a 150 TPD MSW-to-hydrogen plant capital cost of \$126M (total depreciable cost) and a 65% efficiency based on information from an un-named industrial company. The assumed technology was not specified but is assumed to be either a conventional or plasma gasification process.

2005: 15
2015: 16
2025: 17

Applies to Gasification, Tar Reforming, & Quench + Steam Methane Reforming, Shift, and PSA

2005: 15
2015: 16
2025: 17

Catalyst, olive, other

2005: 15
2015: 16
2025: 17

From H2A:
Consists of Mgo (\$0.01MM), boiler chemicals (\$0.03MM), #2 diesel fuel (\$0.08MM), cooling tower chemicals (\$0.01MM)

0.5% of DepreciableCapital

Building an upper-bound FC ought to decrease the cost of a normal FC by the same amount.
You would probably want a similar LearningFactor (maybe even a reference) on the normal FC sheet

Each row corresponds to a technology sheet. Building one of the current sheet will decrease the cost of every technology listed by the corresponding "Factor." The numbers in the first three columns are the 1st, 2nd and 4th numbers of the technology to be cheapened's IClass var

Plant Description
The system is modeled as a 150 TPD MSW-to-hydrogen plant capital cost of \$126M (total depreciable cost) and a 63% efficiency based on information from an un-named industrial company. The assumed technology was not specified but is assumed to be either a conventional or plasma gasification process.

Catalyst, olivine, other

From H2A:
Consists of MgO (\$ 0.11MM), boiler chemicals (\$0.03MM), #2 diesel fuel (\$ 0.08MM), cooling tower chemicals (\$ 0.11MM)

0.5% of DepreciableCapital
All delivery (1-3) sheets with the same J share a LearningFactor (e.g., LT to 0.1TPD and LT to 1.5TPD only need one LearningFactor, since both sheets represent the same underlying technology - LTs). The L for this common factor should always be 1, and the factor should appear on every sheet that shares it.

Building an upper-bound FC ought to decrease the cost of a normal FC by the same amount.
You would probably want a similar LearningFactor (maybe even a reference) on the normal FC sheet

Each row corresponds to a technology sheet. Building one of the current sheet will decrease the cost of every technology listed by the corresponding "Factor." The numbers in the first three columns are the 1st, 2nd and 4th numbers of the technology to-be-cheapened's IClass var

-1	Variable	[Units]	(y-axis,x-axis)	Data	Source Used
VarData	IClass			[1,9,1,2]	
VarData	OClass			[2,1,-1]	
VarData	CYStart	[Year]		2005	
VarData	CYStop	[Year]		2050	
Axis	CY	CY		[2005:2050]	
VarData	IRR	[%]		10%	49
VarData	DepreciationLength	[Years]		20	49
VarData	AnalysisPeriod	[Years]		20	
VarData	Life	[Years]		40	49
Axis	PY	PY		[1:40]	
VarData	DesignCapacity	[kgH2/day]		150,000	49
VarData	DesignCapacity	[kgH2/year]		\$4,750,000	
VarData	CapacityFactor	[% of DesignCapacity]		90%	49
VarData	Location			1	
	DepreciableCapital (Direct)	(Component)		Uninstalled Costs Installation Factor Installed Costs	
				Feed Handling & Drying \$6,000,000.00 250% \$15,000,000.00	49
				Gasification, Tar Reforming & Quench \$8,000,000.00 250% \$20,000,000.00	49
				Compression & Sulfur Removal \$6,000,000.00 250% \$15,000,000.00	49
				Steam Methane Reforming, Shift and PSA \$8,000,000.00 250% \$20,000,000.00	49
				Hydrogen Compression \$1,000,000.00 250% \$2,500,000.00	49
				Steam System and Power Generation \$6,000,000.00 250% \$15,000,000.00	49
				Cooling Water and Other Utilities \$1,500,000.00 250% \$3,750,000.00	49
	DepreciableCapital (Direct)	(Component,CY)		2005 2015 2025	
				Cost Factor 100% 88% 75%	
				Uninstalled Costs \$36,500,000.00 \$34,580,000.00 \$32,500,000.00	
				Installed Costs \$91,250,000.00 \$86,450,000.00 \$81,250,000.00	
	DepreciableCapital (Indirect)	(Component,CY)		2005 2015 2025	
				Site Preparation 1% 1% 1%	15
				Engineering & Design 13% 13% 13%	15
				Process Contingency \$0.00 \$0.00 \$0.00	
				Project Contingency 15% 15% 15%	49
				Other Depreciable Capital \$0.00 \$0.00 \$0.00	
				One-Time Licensing Fees \$0.00 \$0.00 \$0.00	
				Up-Front Permitting Costs 9% 9% 9%	15
VarLinear	DepreciableCapital	[\$]		2005 2015 2025 2050	
Data				\$125,925,000.00 \$119,301,000.00 \$112,125,000.00 \$112,125,000.00	
VarData	LandRequired	[acres]		50	49
	FixedOM	(Component)			
				FTEs 54	15
				Labor Costs \$50.00	15
				Labor Costs \$5,616,000.00	
				Overhead and G&A 20%	15
				Property Tax & Insurance 2%	15
				Rent \$0.00	
				Lic., Permits and Fees \$0.00	
				Matl for Maint. & Repairs 1.5%	49
				Other Fees \$0.00	
				Other Fixed O&M Costs \$0.00	
VarLinear	FixedOM	[\$/year]		2005 2015 2025 2050	
Data				1 \$10,626,450.00 \$10,200,450.00 \$10,200,450.00	
End				40 \$10,626,450.00 \$0.00 \$10,200,450.00 \$10,200,450.00	
VarLinear	OtherFixed	[\$/year]		2005 2050	
Data				1 \$7,000,000.00 \$7,000,000.00	
End				40 \$7,000,000.00 \$7,000,000.00	15
VarLinear	FeedstockEfficiency	(Feedstock,CY)		2005 2015 2025 2050	
Data				Commercial Natural Gas 19.5126 22.9560 39.0252 39.0252	
				Industrial Natural Gas 0.0000 0.0000 0.0000 0.0000	
				Electric Utility Natural Gas 0.0000 0.0000 0.0000 0.0000	
				Commercial Electricity 0.0000 0.0000 0.0000 0.0000	
				Industrial Electricity 21.3559 35.5931 35.5931 35.5931	
				Electric Utility Steam Coal (Central) 0.0000 0.0000 0.0000 0.0000	
				Diesel Fuel 0.0000 0.0000 0.0000 0.0000	
				Biomass 0.0000 0.0000 0.0000 0.0000	
				Ethanol 0.0000 0.0000 0.0000 0.0000	
				Methanol 0.0000 0.0000 0.0000 0.0000	
				Gasoline 0.0000 0.0000 0.0000 0.0000	
				Steam 0.0000 0.0000 0.0000 0.0000	
				Cooling Water 0.0004 0.0004 0.0004 0.0004	
				Deminerlized Water 0.0000 0.0000 0.0000 0.0000	
				Process Water 0.0243 0.0243 0.0243 0.0243	
				Bio-oil 0.0000 0.0000 0.0000 0.0000	
				Electric Utility Steam Coal (Regional) 0.0000 0.0000 0.0000 0.0000	
				MSW (1) 0.0000 0.0000 0.0000 0.0000	
				MSW (2) 0.6500 0.6500 0.6500 0.6500	
	OtherVariableOM	(Component)			
				WT Costs \$0.00	
				SWD Costs \$2,000,000.00	49
				Other Variable Op. Costs \$130,000.00	49
				Royalties \$0.00	15
				Operator Profit \$0.00	
				Subsidies, Tax Incentives \$0.00	
				CO2 Separation & Seq. \$0.00	
VarLinear	OtherVariableOM	[\$/kgH2]		2005 2050	
Data				1 \$0.0432 \$0.0432	
End				40 \$0.0432 \$0.0432	
VarLinear	ByproductEfficiency	(Byproduct,CY)		2005 2050	
Data				1 0.0000 0.0000	
End				40 0.0000 0.0000	
VarLinear	Emissions	(Species,CY)		2005 2015 2025 2050	
Data				Carbon 0 0 0 0	
				GHG Equivalents 0.019853181 0.016875204 0.009926591 0.009926591	19
				NOx 0 0 0 0	
				SOx 0 0 0 0	
				Particulates (PM10) 0 0 0 0	
				Mercury 0 0 0 0	
	ReplacementCosts	[\$]		2005 2015 2025 2050	
VarLinear				1 \$629,625.00 \$596,505.00 \$560,625.00 \$550,558.44	
End				40 \$629,625.00 \$596,505.00 \$560,625.00 \$550,558.44	
Var	LearningFactor	(Technology,Factor)		IClass[1] (I) IClass[2] (J) IClass[4] (L) Factor	
Data				FC-NG-SMR,1.5 (UPPER) 1 5 3 1	5
End				FC-NG-SMR,1.5 1 5 2 1	5
VarData	InitialUnitNo	[unit # in CYBegin]		500	5
VarData	LearningFactorStart			1	5

Plant Description
The system is modeled as a 150 TPD MSW-to-hydrogen plant capital cost of \$126M (total depreciable cost) and a 65% efficiency based on information from an un-named industrial company. The assumed technology was not specified but is assumed to be either a conventional or plasma gasification process.

Applies to Gasification, Tar Reforming, & Quench + Steam Methane Reforming, Shift, and PSA

Catalyst, olive, other

From H2A:
Consists of MgO (\$0.1MM), boiler chemicals (30.03MM), #2 diesel fuel (\$0.08MM), cooling tower chemicals (\$0.01MM)

0.5% of DepreciableCapital

All delivery (I=3) sheets with the same J share a LearningFactor (e.g., LT to 0.1TPD and LT to 1.5TPD only need one LearningFactor, since both sheets represent the same underlying technology - LTS). The L for this common factor should always be 1, and the factor should appear on every sheet that shares it.

Building an upper-bound FC ought to decrease the cost of a normal FC by the same amount. You would probably want a similar LearningFactor (maybe even a reference) on the normal FC sheet.

Each row corresponds to a technology sheet. Building one of the current sheet will decrease the cost of every technology listed by the corresponding "Factor." The numbers in the first three columns are the 1st, 2nd and 4th numbers of the technology to-be-chapmaned's IClass var

-1	Variable	[Units]	(y-axis,x-axis)	Data	Source Used
VarData	IClass			[1,9,1,2]	
VarData	OClass			[2,1,-1]	
VarData	CYStart	[Year]		2005	
VarData	CYStop	[Year]		2050	
Axis	CY	CY		[2005:2050]	
VarData	IRR	[%]		10%	49
VarData	DepreciationLength	[Years]		20	49
VarData	AnalysisPeriod	[Years]		20	
VarData	Life	[Years]		40	49
Axis	PY	PY		[1:40]	
VarData	DesignCapacity	[kgH2/day]		150,000	49
VarData	DesignCapacity	[kgH2/year]		\$4,750,000	49
VarData	CapacityFactor	(% of DesignCapacity)		90%	
VarData	Location			1	
	DepreciableCapital (Direct)	(Component)		Uninstalled Costs Installation Factor Installed Costs	
		Feed Handling & Drying		\$6,000,000.00 250% \$15,000,000.00	49
		Gasification, Tar Reforming & Quench		\$8,000,000.00 250% \$20,000,000.00	49
		Compression & Sulfur Remove		\$6,000,000.00 250% \$15,000,000.00	49
		Steam Methane Reforming, Shift and PSA		\$8,000,000.00 250% \$20,000,000.00	49
		Hydrogen Compressor		\$1,000,000.00 250% \$2,500,000.00	49
		Steam System and Power Generation		\$6,000,000.00 250% \$15,000,000.00	49
		Cooling Water and Other Utilities		\$1,500,000.00 250% \$3,750,000.00	49
	DepreciableCapital (Direct)	(Component,CY)		2005 2015 2025	
		Cost Factor		100% 88% 75%	
		Uninstalled Costs		\$36,500,000.00 \$34,580,000.00 \$32,500,000.00	
		Installed Costs		\$91,250,000.00 \$86,450,000.00 \$81,250,000.00	
	DepreciableCapital (Indirect)	(Component,CY)		2005 2015 2025	
		% of Installed Costs		1% 1% 1%	15
		Site Preparation		1% 1% 1%	15
		Engineering & Design		13% 13% 13%	
		Process Contingency		\$0.00 \$0.00 \$0.00	
		Project Contingency		15% 15% 15%	49
		Other Depreciable Capital		\$0.00 \$0.00 \$0.00	
		One-Time Licensing Fees		\$0.00 \$0.00 \$0.00	
		Up-Front Permitting Costs		9% 9% 9%	15
VarLinear	DepreciableCapital	(\$)		2005 2015 2025 2050	
Data		(CY)		\$125,925,000.00 \$119,301,000.00 \$112,125,000.00 \$112,125,000.00	
VarData	LandRequired	[acres]		50	49
	FixedOM	(Component)			
		FTEs		54	15
		Labor Costs		\$50.00	15
		Labor Costs		\$5,616,000.00	
		Overhead and G&A		20%	15
		Property Tax & Insurance		2%	15
		Rent		\$0.00	
		Lic., Permits and Fees		\$0.00	
		Mart'l for Maint. & Repairs		1.5%	49
		Other Fees		\$0.00	
		Other Fixed O&M Costs		\$0.00	
VarLinear	FixedOM	(\$/year)		2005 2015 2025 2050	
Data		(PY,CY)		1 \$10,626,450.00 \$10,200,450.00 \$10,200,450.00	
End		40 \$10,626,450.00 \$0.00 \$10,200,450.00 \$10,200,450.00			
VarLinear	OtherFixed	(\$/year)		2005 2015 2025 2050	
Data		(PY,CY)		1 \$7,000,000.00 \$7,000,000.00 \$7,000,000.00	
End		40 \$7,000,000.00 \$7,000,000.00 \$7,000,000.00			
VarLinear	FeedstockEfficiency			2005 2015 2025 2050	
		(Feedstock,CY)			
		Commercial Natural Gas		19.5126 22.9560 39.0252 39.0252	2005: 15 2015: 16 2025: 17
		Industrial Natural Gas		0.0000 0.0000 0.0000 0.0000	
		Electric Utility Natural Gas		0.0000 0.0000 0.0000 0.0000	
		Commercial Electricity		0.0000 0.0000 0.0000 0.0000	2005: 15 2015: 16 2025: 17
		Industrial Electricity		21.3559 35.5931 35.5931 35.5931	
		Electric Utility Steam Coal (Central)		0.0000 0.0000 0.0000 0.0000	
		Diesel Fuel		0.0000 0.0000 0.0000 0.0000	
		Biomass		0.0000 0.0000 0.0000 0.0000	
		Ethanol		0.0000 0.0000 0.0000 0.0000	
		Methanol		0.0000 0.0000 0.0000 0.0000	
		Gasoline		0.0000 0.0000 0.0000 0.0000	
		Steam		0.0000 0.0000 0.0000 0.0000	
		Cooling Water		0.0004 0.0004 0.0004 0.0004	2005: 15 2015: 16 2025: 17
		Demineralized Water		0.0000 0.0000 0.0000 0.0000	
		Process Water		0.0243 0.0243 0.0243 0.0243	2005: 15 2015: 16 2025: 17
		Bio-oil		0.0000 0.0000 0.0000 0.0000	
		Electric Utility Steam Coal (Regional)		0.0000 0.0000 0.0000 0.0000	
		MSW (1)		0.0000 0.0000 0.0000 0.0000	
		MSW (2)		0.6500 0.6500 0.6500 0.6500	
	OtherVariableOM	(Component)			
		WT Costs		\$0.00	49
		SWD Costs		\$2,000,000.00	49
		Other Variable Op. Costs		\$130,000.00	49
		Royalties		\$0.00	15
		Operator Profit		\$0.00	
		Subsidies, Tax Incentives		\$0.00	
		CO2 Separation & Seq.		\$0.00	
VarLinear	OtherVariableOM	(\$/kgH2)		2005 2050	
Data		(PY,CY)		1 \$0.0432 \$0.0432	
End		40 \$0.0432 \$0.0432			
VarLinear	ByproductEfficiency			2005 2050	
Data		(Byproduct,CY)		0.0000 0.0000	
End		Byproduct Electricity		0.0000 0.0000	
VarLinear	Emissions			2005 2015 2025 2050	
Data		(Species,CY)			
		Carbon		0 0 0 0	
		GHG Equivalents		0.019853181 0.016875204 0.009926591 0.009926591	19
		NOx		0 0 0 0	
		SOx		0 0 0 0	
		Particulates (PM10)		0 0 0 0	
		Mercury		0 0 0 0	
	ReplacementCosts	(\$)		2005 2015 2025 2050	
VarLinear		(PY,CY)		1 \$629,625.00 \$596,505.00 \$560,625.00 \$560,625.00	
End		40 \$629,625.00 \$596,505.00 \$560,625.00 \$560,625.00			
Var	LearningFactor			(Technology,Factor)	
Data		FC.NG-SMR,1.5 (UPPER)		1 5 3 1	5
End		FC.NG-SMR,1.5		1 5 4 1	5
VarData	InitialUnitNo	[unit # in CYBegin]		500	5
VarData	LearningFactorStart			1	5

Plant Description
The system is modeled as a 150 TPD MSW-to-hydrogen plant capital cost of \$126M (total depreciable cost) and a 65% efficiency based on information from an un-named industrial company. The assumed technology was not specified but is assumed to be either a conventional or plasma gasification process.

2005: 15
2015: 16
2025: 17

Applies to Gasification, Tar Reforming, & Quench + Steam Methane Reforming, Shift, and PSA

2005: 15
2015: 16
2025: 17

Catalyst, olive, other

2005: 15
2015: 16
2025: 17

From H2A:
Consists of MgO (\$0.01MM), boiler chemicals (\$0.03MM), #2 diesel fuel (\$0.08MM), cooling tower chemicals (\$0.01MM)

0.5% of DepreciableCapital

All delivery (1-3) sheets with the same J share a LearningFactor (e.g., LT to 0.1TPD and LT to 1.5TPD only need one LearningFactor, since both sheets represent the same underlying technology - 1.5). The L for this common factor should always be 1, and the factor should appear on every sheet that shares it.

Building an upper-bound FC ought to decrease the cost of a normal FC by the same amount. You would probably want a similar LearningFactor (maybe even a reference) on the normal FC sheet.

Each row corresponds to a technology sheet. Building one of the current sheet will decrease the cost of every technology listed by the corresponding "Factor". The numbers in the first three columns are the 1st, 2nd and 4th numbers of the technology to-be-cheapened's IClass var

0	Variable	[Units]	(y-axis,x-axis)	Data	Source Used
Var/Data	IClass			[2,1,-1]	
Var/Data	OClass			[3,1,-2]	
Var/Data	CVStart	[Year]		2005	
Var/Data	CVStop	[Year]		2050	
Axis	CY	CY		[2005:2050]	
Var/Data	IRR	[%]		10%	3
Var/Data	DepreciationLength	[Years]		15	3
Var/Data	AnalysisPeriod	[Years]		20	
Var/Data	Life	[Years]		20	3
Axis	PY	PY		[1:20]	
Input	DesignCapacity	[kgH2/day]		80,000	
Input	CapacityFactor	[kgH2/year]		29,200,000	
Input	Location	[% of DesignCapacity]		100%	
	AverageCapacity	[kgH2/day]		80,000	
	Distance	[mi]	Pipeline distance	0	
		(Component,CY)		2005 2020	
		(deg. C)	Temperature	25 25	
		(atm)	Pressure	20 20	
	Transmission Pipeline		(Component,CY)		
	Is a pipeline used?	1=yes, 2=no		2 2	
		(deg. C)	Temperature	25 25	
		(atm)	Input Pressure	48 48	
		(atm)	Output Pressure	20 20	
			Compressibility Factor	#NAME? #NAME?	
		[kgH2/day]	Design Flowrate	80,000 80,000	
		[mi]	Length	0 0	
			Diameter	0 0	
		(\$ (ea.))	Overhead, Pipeline Material	\$35,000 \$35,000	
		(\$ (ea.))	Overhead, Miscellaneous	\$95,000 \$95,000	
		(\$ (ea.))	Overhead, Labor	\$185,000 \$185,000	
		(\$ (ea.))	Overhead, ROW	\$40,000 \$40,000	
		(\$ (ea.))	Overhead, Pipeline TOTAL	\$0 \$0	
		[% of Pipeline Cost]	Pipeline Cost Factor	110% 110%	
		(\$/mi)	Unit Cost, Pipeline Material	\$29,656 \$29,656	
		(\$/mi)	Unit Cost, Miscellaneous	\$9,056 \$9,056	
		(\$/mi)	Unit Cost, Labor	\$187,014 \$187,014	
		(\$/mi)	Unit Cost, ROW	\$32,767 \$32,767	
		(\$/mi)	Unit Cost, Pipeline TOTAL	\$257,494 \$257,494	
		(\$)	Total Pipeline cost	\$0 \$0	
	Pipeline Compressors		(Component,CY)		
			Compressibility Factor	#NAME? #NAME?	
		[#]	(total) Quantity	3 2	
		[#]	(needed) Quantity	2 2	
		[kgH2/day] (ea.)	Design Flowrate	40,000 40,000	
		[kgH2/day] (ea.)	Average Flowrate	40,000 40,000	
		[#]	Pressure Ratio/Stage	1.7 1.7	
		[#]	Stages	2 2	
		[%]	Efficiency	80% 80%	
		[kW] (ea.)	Peak Power Req'd	0 0	
		[kW] (ea.)	Average Power Req'd	0 0	
		[kWh/kgH2]	Average Energy Req'd (all plants)	0.00 0.00	
		[% of Gas Compr. Cost]	Compressor Cost Factor	130% 80%	
		(\$)	Pipeline Compressors	\$0 \$0	
	Cryo-Cooler		(Component)		
	Is there a Cryo-Cooler?	1=Yes, 2=No		2 2	
		[kgH2/day]	Max size of cry-cooler	100,000 100,000	
		[#]	Number Plant Required	1 1	
		[kgH2/day]	Design Flow Rate	80,000.00 80,000.00	
		[%]	Average % Utilization	100% 100%	
		(deg. C)	Exit Temp	-193.15 -193.15	
		(atm)	Exit Pressure	20 20	
		[%]	Cost % (relative to full liq. Plant)	50% 50%	
		[%]	Power% (relative to full liq. Plant)	50% 50%	
		[kWh/kgH2]	Peak Energy Req'd (all plants)	0.00 0.00	
		[kWh/kgH2]	Average Energy Req'd (all plants)	0.00 0.00	
		(\$)	Total Capital Cost (all plants)	0 0	
	Storage Compressors		(Component)		
			H2 Compressibility Factor	#NAME? #NAME?	
		[#]	(total) Quantity	1 1	
		[#]	(needed) Quantity	1 1	
		[kgH2/day] (ea.)	Design Flowrate of each comp	80,000 80,000	
		[%]	Average % Utilization	100% 100%	
		[kgH2/day] (ea.)	Average Flowrate	80,000 80,000	
		[#]	Max Pressure Ratio/Stage	1.7 1.7	
		[#]	Stages	5 5	
		[%]	Efficiency	80% 80%	
		(deg. C)	Inlet Temperature	25 25	
		(atm)	Min. Inlet pressure	20 20	
		(atm)	Average Inlet pressure	20 20	
		(atm)	Average Outlet pressure	102 102	
		(atm)	Peak Outlet pressure	184 184	
		[kW] (ea.)	Peak Power Req'd	#NAME? #NAME?	
		[kW] (ea.)	Average Power Req'd	#NAME? #NAME?	
		[kWh/kgH2 of aver. Plant c]	Average Energy Req'd (all plants)	#NAME? #NAME?	
		[% of Gas Compr. Cost]	Compressor Cost Factor	130% 80%	
		(\$)	Storage Compressors	#NAME? #NAME?	
	Buffer Storage, GH2		(Component)		
		(deg. C)	Inlet Temperature	25 25	
		(atm)	Minimum Pressure	20 20	
		(atm)	Average Pressure	102.0 102.0	
		(atm)	Maximum Pressure	183.7 183.7	
		[days]	Stor. at Plant max flow	0.333 0.333	
		[kgH2]	Design Capacity	26,667 26,667	
		(m2)	Land Req'd	5,765 5,765	
		(\$/kgH2)	It Cost, Storage (at max pressure)	\$818.00 \$355.00	
		(\$)	Storage	\$23,994,667 \$10,413,333	
	Truck		(Component)		
		(atm)	Maximum Pressure	180 180	
		[kgH2] (ea.)	Trailer Capacity	280 280	
	Truck Compressors		(Component)		
	Is there a Truck Gas Comp	1=Yes, 2=No		2 1	
			Compressibility Factor	#NAME? #NAME?	
		[#]	(total) Quantity	3 2	
		[#]	(needed) Quantity	2 2	
		[kgH2/day] (ea.)	Design Flowrate	40,000 40,000	
		[kgH2/day] (ea.)	Average Flowrate	40,000 40,000	
		[#]	Max Pressure Ratio/Stage	1.7 1.7	
		[#]	Stages	5 5	
		[%]	Efficiency	80% 80%	
		(deg. C)	Inlet Temperature	25 25	
		(atm)	Min Inlet pressure	20.4 20.4	
		(atm)	Average Inlet pressure	102.0 102.0	
		(atm)	Average Outlet pressure	183.7 183.7	
		(atm)	Peak Outlet pressure	183.7 183.7	
		[kW] (ea.)	Peak Power Req'd	#NAME? #NAME?	
		[kW] (ea.)	Average Power Req'd	#NAME? #NAME?	
		[kWh/kgH2 of aver. Plant c]	Average Energy Req'd (all plants)	#NAME? #NAME?	
		[% of Gas Compr. Cost]	Compressor Cost Factor	130% 80%	
		(\$)	Truck Compressors	#NAME? #NAME?	
	Terminal Bays		(Component)		
		[(#day) (maximum)]	Pick-up Lines	285 285	
		[hours]	(filling) Time/Pick-up	6 6	
		[hours]	(non-filling) Time/Pick-up	1.5 1.5	
		[#]	Bay	90 90	
		[m]	Bay Width	5 5	
		[m/Bay]	Header Length	5 5	
		[m]	Compr. to Header Length	30 30	
		[m]	Storage to Compr. Length	30 30	
		(m2)	Land Req'd	34,462 34,462	
		(\$/Bay)	Unit Cost, Bays	\$10,000.00 \$10,000.00	

brian_james:
Used to calculated design flow rate of compressor.

brian_james:
Peak elec. Power used of capital cost estimation.
Average elec. Power used of electricity cost computation.

brian_james:
Peak elec. Power used of capital cost estimation.
Average elec. Power used of electricity cost computation.

julie_perez:
Corrected equation from H2A so that ratio is of buffer design capacity to trailer design capacity.

brian_james:
Includes 10% installation factor.

brian_james:
Used to calculated design flow rate of compressor.

brian_james:
Time to actually pump/transfer H2 into the trucks.

brian_james:
Time to connect hoses, drive truck to bay, etc.

julie_perez:
0.5 hr for dropoff + 1.0 hr for pickup

Production: GH2 to GT

GH2 to GT

0	Variable	[Units]	(y-axis,x-axis)	Data	Source Used
Var/Data	IClass			[2,1,-1,2]	
Var/Data	OClass			[3,2,-2]	
Var/Data	CYStart	[Year]		2005	
Var/Data	CYStop	[Year]		2050	
Axis	CY	CY		[2005:2050]	
Var/Data	IRR	[%]		10%	3
Var/Data	DepreciationLength	[Years]		15	3
Var/Data	AnalysisPeriod	[Years]		20	
Var/Data	Life	[Years]		20	3
Axis	PY	PY		[1:20]	
Input	DesignCapacity	[kgH2/day]		80,000	
Input	CapacityFactor	[kgH2/year]		29,200,000	
Input	Location	[% of DesignCapacity]		100%	
	AverageCapacity	[kgH2/day]		80,000	
	Distance	[mi]	Pipeline distance	0	
	Input	(deg. C)	(Component,CY)	2005 2020	
		[atm]	Temperature	25 25	
			Pressure	20 20	
	Transmission Pipeline		(Component,CY)		
	Is a pipeline used?	1=Yes, 2=No		2 2	
	(deg. C)		Temperature	25 25	
	[atm]		Input Pressure	48 48	
	[atm]		Output Pressure	20 20	
			Compressibility Factor	#NAME? #NAME?	
	[kgH2/day]		Design Flowrate	80,000 80,000	
	[mi]		Length	0 0	
			Diameter	0 0	
	Overhead, Pipeline Material	[\$ (ea.)		\$35,000 \$35,000	
	Overhead, Miscellaneous	[\$ (ea.)		\$95,000 \$95,000	
	Overhead, Labor	[\$ (ea.)		\$185,000 \$185,000	
	Overhead, ROW	[\$ (ea.)		\$40,000 \$40,000	
	Overhead, Pipeline TOTAL	[\$ (ea.)		\$0 \$0	
	[% of Pipeline Cost]		Pipeline Cost Factor	110% 110%	
	Unit Cost, Pipeline Material	[\$/mi]		\$29,656 \$29,656	
	Unit Cost, Miscellaneous	[\$/mi]		\$8,056 \$8,056	
	Unit Cost, Labor	[\$/mi]		\$187,014 \$187,014	
	Unit Cost, ROW	[\$/mi]		\$32,767 \$32,767	
	Unit Cost, Pipeline TOTAL	[\$/mi]		\$257,494 \$257,494	
	Total Pipeline cost	[\$]		\$0 \$0	
	Pipeline Compressors		(Component,CY)		
	Compressibility Factor	#NAME?	#NAME?		
	(total) Quantity	3	2		
	(needed) Quantity	2	2		
	[kgH2/day] (ea.)	40,000	40,000		
	[kgH2/day] (ea.)	40,000	40,000		
	Pressure Ratio/Stages	1.7	1.7		
	Stages	2	2		
	Efficiency	80%	80%		
	Peak Power Req'd	0	0		
	Average Power Req'd	0	0		
	Average Energy Req'd (all plants)	0.00	0.00		
	Compressor Cost Factor	130%	80%		
	Pipeline Compressors	[\$]		\$0 \$0	
	Cryo-Cooler		(Component)		
	Is there a Cryo-Cooler?	1=Yes, 2=No		2 2	
	[kgH2/day]		Max size of cry-cooler	100,000 100,000	
	[#]		Number Plant Required	1 1	
	[kgH2/day]		Design Flow Rate	80,000.00 80,000.00	
	[%]		Average % Utilization	100% 100%	
	(deg. C)		Exit Temp	-193.15 -193.15	
	[atm]		Exit Pressure	20 20	
	Cost % (relative to full liq. Plant)			50% 50%	
	Power% (relative to full liq. Plant)			50% 50%	
	Peak Energy Req'd (all plants)			0.00 0.00	
	Average Energy Req'd (all plants)			0.00 0.00	
	Total Capital Cost (all plants)	[\$]		0 0	
	Storage Compressors		(Component)		
	H2 Compressibility Factor	#NAME?	#NAME?		
	(total) Quantity	1	1		
	(needed) Quantity	1	1		
	[kgH2/day] (ea.)	80,000	80,000		
	Average % Utilization	100%	100%		
	[kgH2/day] (ea.)	80,000	80,000		
	Max Pressure Ratio/Stages	1.7	1.7		
	Stages	6	6		
	Efficiency	80%	80%		
	Inlet Temperature	25	25		
	Min. Inlet pressure	20	20		
	Average Inlet pressure	20	20		
	Average Outlet pressure	272	272		
	Peak Outlet pressure	408	408		
	Peak Power Req'd	#NAME?	#NAME?		
	Average Power Req'd	#NAME?	#NAME?		
	[kWh/kgH2 of aver. Plant c]	Average Energy Req'd (all plants)	#NAME?		
	Compressor Cost Factor	130%	80%		
	Storage Compressors	[\$]		\$0 \$0	
	Buffer Storage, GH2		(Component)		
	(deg. C)		Inlet Temperature	25 25	
	[atm]		Minimum Pressure	136 136	
	[atm]		Average Pressure	272.1 272.1	
	[atm]		Maximum Pressure	408.2 408.2	
	[days]		Stor. at Plant max flow	0.333 0.333	
	[kgH2]		Design Capacity	26,667 26,667	
	[m2]		Land Req'd	5,765 5,765	
	Cost, Storage (at max pressure)	[\$/kgH2]		\$818.00 \$355.00	
	Storage	[\$]		\$23,994,667 \$10,413,333	
	Truck		(Component)		
	[atm]		Maximum Pressure	476 476	
	[kgH2] (ea.)		Trailer Capacity	657 657	
	Truck Compressors		(Component)		
	Is there a Truck Gas Comp	1=Yes, 2=No		1 1	
	Compressibility Factor	#NAME?	#NAME?		
	(total) Quantity	3	2		
	(needed) Quantity	2	2		
	[kgH2/day] (ea.)	40,000	40,000		
	[kgH2/day] (ea.)	40,000	40,000		
	Max Pressure Ratio/Stages	1.7	1.7		
	Stages	6	6		
	Efficiency	80%	80%		
	Inlet Temperature	25	25		
	Min Inlet pressure	136.1	136.1		
	Average Inlet pressure	272.1	272.1		
	Average Outlet pressure	476.0	476.0		
	Peak Outlet pressure	476.0	476.0		
	Peak Power Req'd	#NAME?	#NAME?		
	Average Power Req'd	#NAME?	#NAME?		
	[kWh/kgH2 of aver. Plant c]	Average Energy Req'd (all plants)	#NAME?		
	Compressor Cost Factor	130%	80%		
	Truck Compressors	[\$]		\$0 \$0	
	Terminal Bays		(Component)		
	Pick-up Limit	122	122		
	(filling) Time/Pick-up	12	12		
	(non-filling) Time/Pick-up	1.5	1.5		
	Bays	69	69		
	Bay Width	5	5		
	Header Length	5	5		
	Compr. to Header Length	30	30		
	Storage to Compr. Length	30	30		
	Land Req'd	26,708	26,708		
	Unit Cost, Bays	\$10,000.00	\$10,000.00		
	Bays	\$690,000.00	\$690,000.00		

brian_james:
Used to calculated design flow rate of
compressor

brian_james:
Peak elec. Power used of capital cost
estimation. Average elec. Power used of
electricity cost computation.

brian_james:
Peak elec. Power used of capital cost
estimation. Average elec. Power used of
electricity cost computation.

julie_perez:
Corrected equation from H2A so that
ratio is of buffer design capacity to
trailer design capacity

brian_james:
Includes 10% installation factor.

brian_james:
Time to actually pump/transfer H2 into the trucks.

brian_james:
Time to connect hoses, drive truck to bay, etc.

Production: GH2 to HPGT

Gh2 to HPGT

0	Variable	[Units]	(y-axis, x-axis)	Data	Source Used
Var/Data	IClass			[2,1,-1,3]	
Var/Data	OClass			[3,3,-2]	
Var/Data	CYStart	[Year]		2020	
Var/Data	CYStop	[Year]		2050	
Axis	CY	CY		[2020-2050]	
Var/Data	IRR	[%]		10%	3
Var/Data	DepreciationLength	[Years]		15	3
Var/Data	AnalysisPeriod	[Years]		20	
Var/Data	Life	[Years]		20	
Axis	PY	PY		[1:20]	3
Input	DesignCapacity	[kgH2/day]		80,000	
Input	CapacityFactor	[kgH2/year]		29,200,000	
Input	Location	[% of DesignCapacity]		100%	
	AverageCapacity	[kgH2/day]		80,000	
	Distance	[mi]	Pipeline distance	0	
	Input from Gaseous Plant	(Component)		2020 2050	
		(deg. C)	Temperature	25 25	
		(atm)	Pressure	20 20	
	Transmission Pipeline	(Component,CY)			
	Is a pipeline used?	1=Yes, 2=No		2 2	
		(deg. C)	Temperature	25 25	
		(atm)	Input Pressure	48 48	
		(atm)	Output Pressure	20 20	
			Compressibility Factor	#NAME? #NAME?	
		[kgH2/day]	Design Flowrate	80,000 80,000	
		[mi]	Length	0 0	
		[mi]	Diameter	0 0	
		(\$ (ea.)	Overhead, Pipeline Material	\$35,000 \$35,000	
		(\$ (ea.)	Overhead, Miscellaneous	\$95,000 \$95,000	
		(\$ (ea.)	Overhead, Labor	\$185,000 \$185,000	
		(\$ (ea.)	Overhead, ROW	\$40,000 \$40,000	
		(\$ (ea.)	Overhead, Pipeline TOTAL	\$0 \$0	
		[% of Pipeline Cost]	Pipeline Cost Factor	110% 110%	
		(\$/mi)	Unit Cost, Pipeline Material	\$29,656 \$29,656	
		(\$/mi)	Unit Cost, Miscellaneous	\$8,056 \$8,056	
		(\$/mi)	Unit Cost, Labor	\$187,014 \$187,014	
		(\$/mi)	Unit Cost, ROW	\$32,767 \$32,767	
		(\$/mi)	Unit Cost, Pipeline TOTAL	\$257,494 \$257,494	
		(\$)	Total Pipeline cost	\$0 \$0	
	Pipeline Compressors	(Component,CY)			
		Compressibility Factor	#NAME? #NAME?		
		(total) Quantity	3 2		
		(needed) Quantity	2 2		
		[kgH2/day] (ea.)	Design Flowrate	40,000 40,000	
		[kgH2/day] (ea.)	Average Flowrate	40,000 40,000	
		[#]	Pressure Ratio/Stage	1.7 1.7	
		[#]	Stages	2 2	
		[%]	Efficiency	80% 80%	
		[kW] (ea.)	Peak Power Req'd	0 0	
		[kW] (ea.)	Average Power Req'd	0 0	
		[kWh/kgH2]	Average Energy Req'd (all plants)	0.00 0.00	
		[% of Gas Compr. Cost]	Compressor Cost Factor	130% 80%	
		(\$)	Pipeline Compressors	\$0 \$0	
	Cryo-Cooler	(Component)			
	Is there a Cryo-Cooler?	1=Yes, 2=No		1 1	
		[kgH2/day]	Max size of cry-cooler	100,000 100,000	10
		[#]	Number Plant Required	1 1	
		[kgH2/day]	Design Flow Rate	80,000.00 80,000.00	
		[%]	Average % Utilization	100% 100%	11
		(deg. C)	Exit Temp	-193.15 -193.15	11
		(atm)	Exit Pressure	20 20	11
		[%]	Cost % (relative to full liq. Plant)	50% 50%	11
		[%]	Elec. Power% (relative to full liq. Plant)	40% 40%	5
		[kWh/kgH2]	Peak Energy Req'd (all plants)	4.06 4.06	
		[kWh/kgH2]	Average Energy Req'd (all plants)	4.06 4.06	
		(\$)	Total Capital Cost (all plants)	42,349,779 42,349,779	
	Storage Compressors	(Component)			
		H2 Compressibility Factor	#NAME? #NAME?		
		(total) Quantity	1 1		5
		(needed) Quantity	1 1		5
		[kgH2/day] (ea.)	Design Flowrate of each compr.	80,000 80,000	
		[%]	Average % Utilization	100% 100%	1
		[kgH2/day] (ea.)	Average Flowrate	80,000 80,000	
		[#]	Max Pressure Ratio/Stage	1.7 1.7	3
		[#]	Stages	4 4	
		[%]	Efficiency	80% 80%	3
		(deg. C)	Inlet Temperature	-193 -193	
		(atm)	Min. Inlet pressure	20 20	3
		(atm)	Average Inlet pressure	20 20	3
		(atm)	Average Outlet pressure	68 68	11
		(atm)	Peak Outlet pressure	136 136	11
		[kW] (ea.)	Peak Power Req'd	#NAME? #NAME?	
		[kW] (ea.)	Average Power Req'd	#NAME? #NAME?	
		[kWh/kgH2 of aver. Plant c	Average Energy Req'd (all plants)	#NAME? #NAME?	
		[% of Gas Compr. Cost]	Compressor Cost Factor	130% 80%	2005: 3
		(\$)	Storage Compressors	#NAME? #NAME?	2020: 1
	Buffer Storage, GH2	(Component)			
		(deg. C)	Inlet Temperature	-193.15 -193.15	11
		(atm)	Minimum Pressure	20 20	3
		(atm)	Average Pressure	68.0 68.0	3
		(atm)	Maximum Pressure	136.1 136.1	11
		[days]	Stor. at Plant max flow	0.333 0.333	5
		[kgH2]	Design Capacity	26,667 26,667	
		[m2]	Land Req'd	5,765 5,765	3
		(\$/kgH2)	Unit Cost, Storage (at max pressure)	\$355.00 \$355.00	4
		(\$)	Storage	\$10,413,333 \$10,413,333	
	Truck	(Component)			
		(atm)	Maximum Pressure	136 136	11
		[kgH2] (ea.)	Trailer Capacity	2100 2100	11
	Truck Compressors	(Component)			
	Is there a Truck Gas Comp	1=Yes, 2=No		1 1	
		Compressibility Factor	#NAME? #NAME?		
		(total) Quantity	2 2		1
		(needed) Quantity	2 2		1
		[kgH2/day] (ea.)	Design Flowrate	40,000 40,000	
		[kgH2/day] (ea.)	Average Flowrate	40,000 40,000	
		[#]	Max Pressure Ratio/Stage	1.7 1.7	3
		[#]	Stages	4 4	
		[%]	Efficiency	80% 80%	1
		(deg. C)	Inlet Temperature	-193.15 -193.15	11
		(atm)	Min Inlet pressure	20.0 20.0	3
		(atm)	Average Inlet pressure	68.0 68.0	3
		(atm)	Average Outlet pressure	136.0 136.0	3
		(atm)	Peak Outlet pressure	136.0 136.0	3
		[kW] (ea.)	Peak Power Req'd	#NAME? #NAME?	
		[kW] (ea.)	Average Power Req'd	#NAME? #NAME?	
		[kWh/kgH2 of aver. Plant c	Average Energy Req'd (all plants)	#NAME? #NAME?	
		[% of Gas Compr. Cost]	Compressor Cost Factor	80% 80%	1
		(\$)	Truck Compressors	#NAME? #NAME?	
	Terminal Bays	(Component)			
		[#(day) (maximum)	Pick-up Limit	38 38	
		(hours)	(filling) Time/Pick-up	2 2	11
		(hours)	(non-filling) Time/Pick-up	1 1	11
		[#]	Bays	5 5	
		[m]	Bay Width	5 5	3
		[mBay]	Header Length	5 5	
		[m]	Compr. to Header Length	30 30	3
		[m]	Storage to Compr. Length	30 30	3
		[m2]	Land Req'd	3,077 3,077	
		(\$/Bay)	Unit Cost, Bays	\$10,000.00 \$10,000.00	3
		(\$)	Bays	\$50,000.00 \$50,000.00	
	Liquefiers	(Component)			
		[%]	Liq. Size % of prod. Plant	10% 10%	5

julie_perez:
Values from Source 3 are taken from Liquid related pages.

julie_perez:
Adjusted to 40% to mimic the improvement in electricity consumption in liquefiers in 2025.

brian_james:
Used to calculated design flow rate of compressor.

brian_james:
Peak elec. Power used of capital cost estimation.
Average elec. Power used of electricity cost computation.

brian_james:
Peak elec. Power used of capital cost estimation.
Average elec. Power used of electricity cost computation.

julie_perez:
Corrected equation from H2A so that ratio is of buffer design capacity to trailer design capacity.

brian_james:
Includes 10% installation factor.

brian_james:
Used to calculated design flow rate of compressor.

brian_james:
Time to actually pump/transfer H2 into the trucks.

brian_james:
Time to connect hoses, drive truck to bay, etc.

Plumbing, electrical and instrumentation

Production: GH2 to CryoGT

julie_perez:
20% is the H2A Standard.

0	Variable	[Units]	(y-axis,x-axis)	Data	Source Used
Var/Data	IClass			[2,1,-1,4]	
Var/Data	OClass			[3,4,-2]	
Var/Data	CYStart	[Year]		2005	
Var/Data	CYStop	[Year]		2050	
Axis	CY	CY		[2005-2050]	
Var/Data	IRR	[%]		10%	3
Var/Data	DepreciationLength	[Years]		15	3
Var/Data	AnalysisPeriod	[Years]		20	
Var/Data	Life	[Years]		20	3
Axis	PY	PY		[1-20]	
Input	DesignCapacity	[kgH2/day]		80,000	
Input	CapacityFactor	[kgH2/year]		29,200,000	
Input	Location	[% of DesignCapacity]		100%	
Input	AverageCapacity	[kgH2/day]		2	
Input	Distance	[mi]	Pipeline distance	80,000	
Input		(Component,CY)		0	
		(deg. C)	Temperature	2005 2020	
		[atm]	Pressure	25 25	
	Transmission Pipeline		(Component,CY)	20 20	
		Is a pipeline used?	1=yes, 2=no	2 2	
		(deg. C)	Temperature	25 25	
		[atm]	Input Pressure	48 48	
		[atm]	Output Pressure	20 20	
			Compressibility Factor	#NAME? #NAME?	
		[kgH2/day]	Design Flowrate	80,000 80,000	
		[m]	Length	0 0	
			Diameter	0 0	
		[\$ (ea.)	Overhead, Pipeline Material	\$35,000 \$35,000	
		[\$ (ea.)	Overhead, Miscellaneous	\$95,000 \$95,000	
		[\$ (ea.)	Overhead, Labor	\$185,000 \$185,000	
		[\$ (ea.)	Overhead, ROW	\$40,000 \$40,000	
		[\$ (ea.)	Overhead, Pipeline TOTAL	\$0 \$0	
		[% of Pipeline Cost]	Pipeline Cost Factor	110% 110%	
		[\$/mi]	Unit Cost, Pipeline Material	\$29,656 \$29,656	
		[\$/mi]	Unit Cost, Miscellaneous	\$8,056 \$8,056	
		[\$/mi]	Unit Cost, Labor	\$187,014 \$187,014	
		[\$/mi]	Unit Cost, ROW	\$32,767 \$32,767	
		[\$/mi]	Unit Cost, Pipeline TOTAL	\$257,494 \$257,494	
		[\$]	Total Pipeline cost	\$0 \$0	
	Pipeline Compressors		(Component,CY)		
		[#]	Compressibility Factor	#NAME? #NAME?	
		[#]	(total) Quantity	3 2	
		[kgH2/day] (ea.)	Design Flowrate	40,000 40,000	
		[kgH2/day] (ea.)	Average Flowrate	40,000 40,000	
		[#]	Pressure Ratio/Stage	1.7 1.7	
		[#]	Stages	2 2	
		[%]	Efficiency	80% 80%	
		[kW] (ea.)	Peak Power Req'd	0 0	
		[kW] (ea.)	Average Power Req'd	0 0	
		[kWh/kgH2]	Energy Req'd (all plants)	0.00 0.00	
		[% of Gas Compr. Cost]	Compressor Cost Factor	130% 80%	
		[\$]	Pipeline Compressors	\$0 \$0	
	Cryo-Cooler		(Component)		
		Is there a Cryo-Cooler?	1=Yes, 2=No	2 2	
		[kgH2/day]	Max size of cry-cooler	100,000 100,000	
		[#]	Number Plant Required	1 1	
		[kgH2/day]	Design Flow Rate	80,000.00 80,000.00	
		[%]	Average % Utilization	100% 100%	
		(deg. C)	Exit Temp	-193.15 -193.15	
		[atm]	Exit Pressure	20 20	
		[%]	Cost % (relative to full liq. Plant)	50% 50%	
		[%]	Power % (relative to full liq. Plant)	50% 50%	
		[kWh/kgH2]	Peak Energy Req'd (all plants)	0.00 0.00	
		[kWh/kgH2]	Energy Req'd (all plants)	0.00 0.00	
		[\$]	Total Capital Cost (all plants)	0 0	
	Storage Compressors		(Component)		
		[#]	H2 Compressibility Factor	#NAME? #NAME?	
		[#]	(total) Quantity	1 1	
		[kgH2/day] (ea.)	Design Flowrate of each compr.	80,000 80,000	
		[%]	Average % Utilization	100% 100%	
		[kgH2/day] (ea.)	Average Flowrate	80,000 80,000	
		[#]	Max Pressure Ratio/Stage	1.7 1.7	
		[#]	Stages	6 6	
		[%]	Efficiency	80% 80%	
		(deg. C)	Inlet Temperature	25 25	
		[atm]	Min. Inlet pressure	20 20	
		[atm]	Average Inlet pressure	20 20	
		[atm]	Average Outlet pressure	20 20	
		[atm]	Peak Outlet pressure	20 20	
		[kW] (ea.)	Peak Power Req'd	#NAME? #NAME?	
		[kW] (ea.)	Average Power Req'd	#NAME? #NAME?	
		[kWh/kgH2 of aver. Plant]	Energy Req'd (all plants)	#NAME? #NAME?	
		[% of Gas Compr. Cost]	Compressor Cost Factor	130% 80%	
		[\$]	Storage Compressors	#NAME? #NAME?	
	Buffer Storage, GH2		(Component)		
		(deg. C)	Inlet Temperature	25 25	
		[atm]	Minimum Pressure	20 20	
		[atm]	Average Pressure	20.0 20.0	
		[atm]	Maximum Pressure	20.1 20.1	
		[days]	Stor. at Plant max flow	0.000 0.000	
		[kgH2]	Design Capacity	0 0	
		[m2]	Land Req'd	0 0	
		[\$/kgH2]	Cost, Storage (at max pressure)	\$816.00 \$355.00	
		[\$]	Storage	\$0 \$0	
	Truck		(Component)		
		[atm]	Maximum Pressure	20.10 20.1	5
		[kgH2] (ea.)	Trailer Capacity	4372 4372	3
	Truck Compressors		(Component)		
		Is there a Truck Gas Comp	1=Yes, 2=No	2 2	
		[#]	Compressibility Factor	#NAME? #NAME?	
		[#]	(total) Quantity	3 3	
		[kgH2/day] (ea.)	Design Flowrate	40,000 40,000	
		[kgH2/day] (ea.)	Average Flowrate	40,000 40,000	
		[#]	Max Pressure Ratio/Stage	1.7 1.7	
		[#]	Stages	1 1	
		[%]	Efficiency	80% 80%	
		(deg. C)	Inlet Temperature	25 25	
		[atm]	Min Inlet pressure	20.0 20.0	
		[atm]	Average Inlet pressure	20.0 20.0	
		[atm]	Average Outlet pressure	20.0 20.0	
		[atm]	Peak Outlet pressure	20.0 20.0	
		[kW] (ea.)	Peak Power Req'd	0 0	
		[kW] (ea.)	Average Power Req'd	0 0	
		[kWh/kgH2 of aver. Plant]	Energy Req'd (all plants)	0.000 0.000	
		[% of Gas Compr. Cost]	Compressor Cost Factor	130% 80%	
		[\$]	Truck Compressors	#NAME? #NAME?	
	Terminal Bays		(Component)		
		[#] (day) (maximum)	Pick-up Limit	18 18	
		[hours]	(filling) Time/Pick-up	2 2	3
		[hours]	(non-filling) Time/Pick-up	1 1	3
		[#]	Bays	3 3	
		[m]	Bay Width	5 5	3
		[m/Bay]	Header Length	5 5	
		[m]	Pump to Header Length	30.5 30.5	3
		[m]	Storage to Compr. Length	26.5 30.5	3
		[m2]	Land Req'd	2,338 2,338	
		[\$/Bay]	Unit Cost, Bays	\$25,000.00 \$25,000.00	3
		[\$]	Bays	\$75,000.00 \$75,000.00	
	Liquefiers		(Component)		
		[%]	Liq. Size % of prod. Plant	100% 100%	3
		[kgH2/day] (total)	Desired Max Total Liq Flowrate	80,000 80,000	

julie_perex:
Increased pressure by 0.1 atm to make sure dependent cells do not have a #DIV0 error.

brian_james:
Time to actually pump/transfer H2 into the trucks.
brian_james:
Time to connect hoses, drive truck to bay, etc.

Plumbing, electrical and instrumentation

Production: GH2 to LT

julie_perez:
Source 3 has 70% cap factor

brian_james:
Energy per kgH2 computed at full utilization.

julie_perez:
Corrected Learning to Cumulative Average Theory. 10 Apr 2007.

Appendix J

Production: GH2 to PL

0	Variable	[Units]	(y-axis,x-axis)	Data	Source Used
Var/Data	IClass			[2,1,-1,5]	
Var/Data	OClass			[3,5,1]	
Var/Data	CYStart	[Year]		2005	
Var/Data	CYStop	[Year]		2050	
Axis	CY	CY		[2005-2050]	
Var/Data	IRR	[%]		10%	3
Var/Data	DepreciationLength	[Years]		15	3
Var/Data	AnalysisPeriod	[Years]		20	
Var/Data	Life	[Years]		20	3
Axis	PY	PY		[1-20]	
Input	DesignCapacity	[kgH2/day]		80,000	
Input	CapacityFactor	[kgH2/year]		29,200,000	
Input	Location	[% of DesignCapacity]		100%	
	AverageCapacity	[kgH2/day]		2	
	Distance	[mi]	Pipeline distance	80,000	
	Input	(Component,CY)		0	
		(deg. C)	Temperature	2005 2020	
		[atm]	Pressure	25 25	3
	Transmission Pipeline	(Component,CY)		20 20	3
		1=yes, 2=no		1 1	
		(deg. C)	Temperature	25 25	3
		[atm]	Input Pressure	48 48	3
		[atm]	Output Pressure	20 20	3
		Compressibility Factor		#NAME? #NAME?	
		[kgH2/day]	Design Flowrate	80,000 80,000	
		[m]	Length	0 0	
		[m]	Diameter	0 0	
		Overhead, Pipeline Material		\$35,000 \$35,000	3
		Overhead, Miscellaneous		\$95,000 \$95,000	3
		Overhead, Labor		\$185,000 \$185,000	3
		Overhead, ROW		\$40,000 \$40,000	3
		Overhead, Pipeline TOTAL		\$0 \$0	
		[% of Pipeline Cost]	Pipeline Cost Factor	110% 110%	3
		Unit Cost, Pipeline Material		\$29,656 \$29,656	
		Unit Cost, Miscellaneous		\$8,056 \$8,056	
		Unit Cost, Labor		\$187,014 \$187,014	
		Unit Cost, ROW		\$32,767 \$32,767	
		Unit Cost, Pipeline TOTAL		\$257,494 \$257,494	
		Total Pipeline cost		\$0 \$0	
	Pipeline Compressors	(Component,CY)			
		Compressibility Factor		#NAME? #NAME?	
		(total) Quantity		3 2	3
		(needed) Quantity		2 2	3
		[kgH2/day] (ea.)	Design Flowrate	40,000 40,000	
		[kgH2/day] (ea.)	Average Flowrate	40,000 40,000	
		Pressure Ratio/Stage		1.7 1.7	3
		[#]	Stages	2 2	
		Efficiency		80% 80%	3
		[kW] (ea.)	Peak Power Req'd	#NAME? #NAME?	
		[kW] (ea.)	Average Power Req'd	#NAME? #NAME?	
		[kWh/kgH2]	Energy Req'd (all plants)	#NAME? #NAME?	
		Compressor Cost Factor		130% 80%	2005: 3
		[% of Gas Compr. Cost]	Pipeline Compressors	#NAME? #NAME?	2020: 1
	Cryo-Cooler	(Component)			
		1=Yes, 2=No		2 2	
		[kgH2/day]	Max size of cry-cooler	100,000 100,000	
		[#]	Number Plant Required	1 1	
		[kgH2/day]	Design Flow Rate	80,000.00 80,000.00	
		[%]	Average % Utilization	100% 100%	
		(deg. C)	Exit Temp	-193.15 -193.15	
		[atm]	Exit Pressure	20 20	
		[%]	1st % (relative to full liq. Plant)	50% 50%	
		[%]	aver % (relative to full liq. Plant)	50% 50%	
		[kWh/kgH2]	Peak Energy Req'd (all plants)	0.00 0.00	
		[kWh/kgH2]	Energy Req'd (all plants)	0.00 0.00	
		Total Capital Cost (all plants)		0 0	
	Storage Compressors	(Component)			
		H2 Compressibility Factor		#NAME? #NAME?	
		(total) Quantity		1 1	
		(needed) Quantity		1 1	
		[kgH2/day] (ea.)	Design Flowrate of each compr.	80,000 80,000	
		[%]	Average % Utilization	100% 100%	
		[kgH2/day] (ea.)	Average Flowrate	80,000 80,000	
		[#]	Max Pressure Ratio/Stage	1.7 1.7	
		[#]	Stages	6 6	
		Efficiency		80% 80%	
		(deg. C)	Inlet Temperature	25 25	
		[atm]	Min. Inlet pressure	20 20	
		[atm]	Average Inlet pressure	20 20	
		[atm]	Average Outlet pressure	20 20	
		[atm]	Peak Outlet pressure	20 20	
		[kW] (ea.)	Peak Power Req'd	#NAME? #NAME?	
		[kW] (ea.)	Average Power Req'd	#NAME? #NAME?	
		[kWh/kgH2 of aver. Plant]	Energy Req'd (all plants)	#NAME? #NAME?	
		Compressor Cost Factor		130% 80%	
		[% of Gas Compr. Cost]	Storage Compressors	#NAME? #NAME?	
	Buffer Storage, GH2	(Component)			
		(deg. C)	Inlet Temperature	25 25	
		[atm]	Minimum Pressure	20 136	
		[atm]	Average Pressure	2.0 272.1	
		[atm]	Maximum Pressure	408.2 408.2	
		[days]	Stor. at Plant max flow	0.000 0.000	
		[kgH2]	Design Capacity	0 0	
		[m2]	Land Req'd	0 0	
		1st. Storage (at max pressure)		\$818.00 \$355.00	
		Storage		\$0 \$0	
	Truck	(Component)			
		[atm]	Maximum Pressure	N/A N/A	
		[kgH2] (ea.)	Trailer Capacity	N/A N/A	
	Truck Compressors	(Component)			
		1=Yes, 2=No		2 2	
		Compressibility Factor		N/A N/A	
		(total) Quantity		3 3	
		(needed) Quantity		2 2	
		[kgH2/day] (ea.)	Design Flowrate	40,000 40,000	
		[kgH2/day] (ea.)	Average Flowrate	40,000 40,000	
		Max Pressure Ratio/Stage		1.7 1.7	
		[#]	Stages	N/A N/A	
		Efficiency		80% 80%	
		(deg. C)	Inlet Temperature	25 25	
		[atm]	Min. Inlet pressure	20.0 136.1	
		[atm]	Average Inlet pressure	2.0 272.1	
		[atm]	Average Outlet pressure	476.2 476.2	
		[atm]	Peak Outlet pressure	476.2 476.2	
		[kW] (ea.)	Peak Power Req'd	0 0	
		[kW] (ea.)	Average Power Req'd	0 0	
		[kWh/kgH2 of aver. Plant]	Energy Req'd (all plants)	0.000 0.000	
		Compressor Cost Factor		130% 80%	
		[% of Gas Compr. Cost]	Truck Compressors	\$0 \$0	
	Terminal Bays	(Component)			
		[#(day) (maximum)]	Pick-up Limit	0 0	
		[hours]	(filling) Time/Pick-up	0 0	
		[hours]	(non-filling) Time/Pick-up	0 0	
		[#]	Bays	0 0	
		[m]	Bay Width	5 5	
		[m/Bay]	Header Length	5 5	
		[m]	Pump to Header Length	30 30	
		[m]	Storage to Compr. Length	30 30	
		[m2]	Land Req'd	0 0	
		Unit Cost, Bays		\$25,000.00 \$25,000.00	
		[#]	Bays	\$0.00 \$0.00	
	Liquefiers	(Component)			
		[%]	Liq. Size % of prod. Plant	10% 10%	5

Production: GH2 to PL

GH2 to PL

0	Variable	[Units]	(y-axis, x-axis)	Data	Source Used
Var/Data	IClass			[2,3,-3,1]	
Var/Data	OClass			[3,3,-2]	
Var/Data	CYStart	[Year]		2020	
Var/Data	CYStop	[Year]		2050	
Axis	CY			[2020-2050]	
Var/Data	IRR	[%]		10%	3
Var/Data	DepreciationLength	[Years]		15	3
Var/Data	AnalysisPeriod	[Years]		20	
Var/Data	Life	[Years]		20	3
Axis	PY			[1-20]	
	DesignCapacity	[kgH2/day]		155,236	
Input	DesignCapacity	[kgH2/day]		56,661,070	
Input	CapacityFactor	[% of DesignCapacity]		90%	
Var/Data	Location			5	
	AverageCapacity	[kgH2/day]		139,712	
	Distance	[mi]		346	
Input			(Component)	2020 2050	
		[deg. C]	Temperature	25 25	3
		[atm]	Pressure	20 20	3
Transmission Pipeline					
		(Component,CY)			
	Is a pipeline used?	1=Yes, 2=No		1	1
		[deg. C]	Temperature	25	25
		[atm]	Input Pressure	68	68
		[atm]	Output Pressure	48	48
			Compressibility Factor	#NAME?	#NAME?
		[kgH2/day]	Design Flowrate	155,236	155,236
		[mi]	Length	346	346
		[in]	Diameter	#NAME?	#NAME?
		[\$] (ea.)	Overhead, Pipeline Material	\$35,000	\$35,000
		[\$] (ea.)	Overhead, Miscellaneous	\$95,000	\$95,000
		[\$] (ea.)	Overhead, Labor	\$185,000	\$185,000
		[\$] (ea.)	Overhead, ROW	\$40,000	\$40,000
		[\$] (ea.)	Overhead, Pipeline TOTAL	\$355,000	\$355,000
		[% of Pipeline Cost]	Pipeline Cost Factor	110%	110%
		[\$/mi]	Jnit Cost, Pipeline Material	#NAME?	#NAME?
		[\$/mi]	Unit Cost, Miscellaneous	#NAME?	#NAME?
		[\$/mi]	Unit Cost, Labor	#NAME?	#NAME?
		[\$/mi]	Unit Cost, ROW	#NAME?	#NAME?
		[\$/mi]	Unit Cost, Pipeline TOTAL	#NAME?	#NAME?
		[\$]	Total Pipeline cost	#NAME?	#NAME?
Pipeline Compressors					
		(Component,CY)			
			Compressibility Factor	#NAME?	#NAME?
		[#]	(total) Quantity	2	2
		[#]	(needed) Quantity	2	2
		[kgH2/day] (ea.)	Design Flowrate	77,618	77,618
		[kgH2/day] (ea.)	Average Flowrate	69,856	69,856
		[#]	Pressure Ratio/Stage	1.7	1.7
		[#]	Stages	3	3
		[%]	Efficiency	80%	80%
		[kW] (ea.)	Peak Power Req'd	#NAME?	#NAME?
		[kW] (ea.)	Average Power Req'd	#NAME?	#NAME?
		[kWh/kgH2]	e Energy Req'd (all plants)	#NAME?	#NAME?
		[% of Gas Compr. Cost]	Compressor Cost Factor	80%	80%
		[\$]	Pipeline Compressors	#NAME?	#NAME?
Cryo-Cooler					
		(Component)			
	Is there a Cryo-Cooler?	1=Yes, 2=No		1	1
		[kgH2/day]	Max size of cry-cooler	100,000	100,000
		[#]	Number Plant Required	2	2
		[kgH2/day]	Design Flow Rate	77,617.90	77,617.90
		[%]	Average % Utilization	100%	100%
		[deg. C]	Exit Temp	-193.15	-193.15
		[atm]	Exit Pressure	20	20
		[%]	% (relative to full liq. Plant)	50%	50%
		[%]	% (relative to full liq. Plant)	40%	40%
		[kWh/kgH2]	k Energy Req'd (all plants)	4.09	4.09
		[kWh/kgH2]	e Energy Req'd (all plants)	4.09	4.09
		[\$]	tal Capital Cost (all plants)	83,371,028	83,371,028
Storage Compressors					
		(Component)			
			H2 Compressibility Factor	#NAME?	#NAME?
		[#]	(total) Quantity	1	1
		[#]	(needed) Quantity	1	1
		[kgH2/day] (ea.)	gn Flowrate of each compr.	155,236	155,236
		[%]	Average % Utilization	100%	100%
		[kgH2/day] (ea.)	Average Flowrate	155,236	155,236
		[#]	Max Pressure Ratio/Stage	1.7	1.7
		[#]	Stages	4	4
		[%]	Efficiency	80%	80%
		[deg. C]	Inlet Temperature	-193	-193
		[atm]	Min. Inlet pressure	20	20
		[atm]	Average Inlet pressure	20	20
		[atm]	Average Outlet pressure	68	68
		[atm]	Peak Outlet pressure	136	136
		[kW] (ea.)	Peak Power Req'd	#NAME?	#NAME?
		[kW] (ea.)	Average Power Req'd	#NAME?	#NAME?
		[kWh/kgH2 of aver. Plant c	oe Energy Req'd (all plants)	#NAME?	#NAME?
		[% of Gas Compr. Cost]	Compressor Cost Factor	80%	80%
		[\$]	Storage Compressors	#NAME?	#NAME?
Buffer Storage, GH2					
		(Component)			
		[deg. C]	Inlet Temperature	-193.15	-193.15
		[atm]	Minimum Pressure	20	20
		[atm]	Average Pressure	68.0	68.0
		[atm]	Maximum Pressure	136.1	136.1
		[days]	Stor. at Plant max flow	0.333	0.333
		[kgH2]	Design Capacity	51,745	51,745
		[m2]	Land Req'd	9,797	9,797
		[\$/kgH2]	Storage (at max pressure)	\$355.00	\$355.00
		[\$]	Storage	\$20,206,528	\$20,206,528
Truck					
		(Component)			
		[atm]	Maximum Pressure	136	136
		[kgH2] (ea.)	Trailer Capacity	2100	2100
Truck Compressors					
		(Component)			
	Is there a Truck Gas Comp	1=Yes, 2=No		1	1
			Compressibility Factor	#NAME?	#NAME?
		[#]	(total) Quantity	2	2
		[#]	(needed) Quantity	2	2
		[kgH2/day] (ea.)	Design Flowrate	77,618	77,618
		[kgH2/day] (ea.)	Average Flowrate	69,856	69,856
		[#]	Max Pressure Ratio/Stage	1.7	1.7
		[#]	Stages	4	4
		[%]	Efficiency	80%	80%
		[deg. C]	Inlet Temperature	-193.15	-193.15
		[atm]	Min Inlet pressure	20.0	20.0
		[atm]	Average Inlet pressure	68.0	68.0
		[atm]	Average Outlet pressure	136.0	136.0
		[atm]	Peak Outlet pressure	136.0	136.0
		[kW] (ea.)	Peak Power Req'd	#NAME?	#NAME?
		[kW] (ea.)	Average Power Req'd	#NAME?	#NAME?
		[kWh/kgH2 of aver. Plant c	oe Energy Req'd (all plants)	#NAME?	#NAME?
		[% of Gas Compr. Cost]	Compressor Cost Factor	80%	80%
		[\$]	Truck Compressors	#NAME?	#NAME?
Terminal Bays					
		(Component)			
		[#] (maximum)	Pick-up Limit	74	74
		[hours]	(filling) Time/Pick-up	2	2
		[hours]	(non-filling) Time/Pick-up	1	1
		[#]	Bays	10	10
		[m]	Bay Width	5	5
		[m/Bay]	Header Length	5	5
		[m]	Compr. to Header Length	30	30
		[m]	Storage to Compr. Length	30	30
		[m2]	Land Req'd	4,923	4,923
		[\$/Bay]	Unit Cost, Bays	\$10,000.00	\$10,000.00
		[\$]	Bays	\$100,000.00	\$100,000.00
Liquefiers					
		(Component)			
		[%]	Liq. Size % of prod. Plant	10%	10%
		[kgH2/day] (total)	red Max Total Liq.Flowrate	15,524	15,524

julie_perez:
Adjusted to 40% to mimic the improvement in electricity consumption in liquefiers in 2025.

brian_james:
Used to calculated design flow rate of compressor.

brian_james:
Peak elec. Power used of capital cost estimation.
Average elec. Power used of electricity cost computation.

brian_james:
Peak elec. Power used of capital cost estimation.
Average elec. Power used of electricity cost computation.

julie_perez:
Corrected equation from H2A so that ratio is of buffer design capacity to trailer design capacity.

brian_james:
Includes 10% installation factor.

brian_james:
Used to calculated design flow rate of compressor.

brian_james:
Time to actually pump/transfer H2 into the trucks.

brian_james:
Time to connect hoses, drive truck to bay, etc.

Plumbing, electrical and instrumentation

	[kgH2/day]	Liquifier Flowrate Limit	100,000	100,000	10	
	[#]	Quantity	1	1		
	[kgH2/day] (ea.)	Design Flowrate	15,524	15,524		
	[%]	Average % Utilization	50%	50%	5	brian_james: Energy per kgH2 computed at full utilization.
	[kgH2/day] (ea.)	Average Flowrate	7,762	7,762		
	[m2]	Land Req'd	11,108	11,108		
	[kWh/kgH2 of LH2]	Average Energy Req'd	13.98	13.98		julie_perez: Corrected Learning to Cumulative Average Theory. 10 Apr 2007.
	kW	Average Power Req'd	4,522	4,522		
	[kWh/kgH2 of aver. Plant crie Energy Req'd (all plants)]		0.78	0.78		
	[\$]	Liquifier Cost	\$35,929,721	\$35,929,721		
		Learning Factor	0.9	0.9	5	
LH2 Outage Storage		(Component)				
	[% Lique storage vol.]	Usable Capacity	90%	90%	3	
	[#]	ays of full Plant Production	5	5	3	
	[kgH2]	Storage Design Capacity	862,421	862,421		
	[m2]	Land Req'd	1,280	1,280		
	[\$]	LH2 Storage Cost	\$28,501,119	\$28,501,119	3	
LH2 Evaporator		(Component)				
	Is there a LH2-Evap.?	1=Yes, 2=No	2	2		
	%	Evap Flow Rate (% of total	100%	100%	5	Plumbing, electrical and instrumentation
	[kgH2/day]	Evap Design Flow Rate	155,236	155,236		
	[\$]	Evaporator Cost	\$0	\$0	3	
Terminal (LH2 Pumps)		(Component)				
	[kgH2/hr] (total)	(system) Req'd Flowrate	9,702	9,702		
	[% of Req'd Flowrate]	Factor of Safety	50%	50%	3	
	[#]	Quantity	2	2	3	
	[kgH2/hour] (ea.)	Design Flowrate	7,277	7,277		
	[\$/kgH2/hr]	Unit Cost, Pumps	\$150.00	\$150.00	3	
	[\$]	LH2 Pump Cost	\$2,183,004	\$2,183,004		
Costs						
DepreciableCapital (Direct)		(Component)				
	[\$]	Transmission Pipeline	#NAME?	#NAME?		
	[\$]	Pipeline Compressors	#NAME?	#NAME?		
	[\$]	Cryo-Cooler	\$83,371,028	\$83,371,028		
	[\$]	Storage Compressors	#NAME?	#NAME?		
	[\$]	Buffer Storage	\$20,206,825	\$20,206,528		brian_james: Liquifier and storage only. (No pipeline land included.)
	[\$]	Truck Compressors	#NAME?	#NAME?		
	[\$/m]	Unit Cost, Piping	\$300	\$300	3	
	[\$]	Piping	\$33,000	\$33,000		
	[\$]	Bays	\$100,000	\$100,000		
	[\$]	Buildings and Structures	\$50,000	\$50,000	3	julie_perez: 20% is the H2A Standard.
	[\$]	Truck Scale	\$80,000	\$80,000	3	
	[\$]	Liquifiers	\$35,929,721	\$35,929,721		
	[\$]	LH2 Storage	\$28,501,119	\$28,501,119		
	[\$]	LH2 Evaporator	\$0	\$0		
	[\$]	LH2 Pumps	\$2,183,004	\$2,183,004		
	[\$]	Installed Costs	#NAME?	#NAME?		
DepreciableCapital (Indirect)		(Component)				
	[% of Installed Costs]	Site Preparation	12%		3	
	[% of Installed Costs]	Engineering & Design	32%		3	
	[\$]	Process Contingency	\$0.00			
	[% of Installed Costs]	Project Contingency	25%		3	
	[\$]	Other Depreciable Capital	\$0.00			
	[% of Installed Costs]	One-Time Licensing Fees	1.5%		3	
	[% of Installed Costs]	Up-Front Permitting Costs	4%		3	
Var/Nearest Data	DepreciableCapital	[\$]	(CY)	2020	2050	
Var/Data	LandRequired	[acres]		#NAME?	#NAME?	
FixedOM		(Component)				
	[hours/year]	Labor Req'd	17,520		3	
	[\$/hour]	Labor Costs	\$24.20		3	
	[\$/year]	Labor Costs	\$423,984.00			
	[% of Labor]	Overhead and G&A	20%		5	
	[% of DepreciableCapital]	Property Tax & Insurance	2.5%		3	
	[\$/year]	Rent	\$0.00			
	[\$/year]	Lic., Permits and Fees	\$0.00		5	
	[% of Installed Costs]	Matt for Maint. & Repairs	0.5%		3	
	[\$/year]	Other Fees	\$0.00		3	
Var/Nearest Data	FixedOM	[\$/year]	Other Fixed O&M Costs	(PY,CY)	2020	2050
End				#NAME?	#NAME?	
Var/Nearest Data	OtherFixed	[\$/year]		(PY,CY)	2020	2050
End				1	\$0.00	\$0.00
Var/Nearest Data	FeedstockEfficiency		(Feedstock,CY)	2020	2050	
	[GJH2/GJFeedstock]	Commercial Natural Gas	0.0000	0.0000		
	[GJH2/GJFeedstock]	Industrial Natural Gas	0.0000	0.0000		
	[GJH2/GJFeedstock]	Electric Utility Natural Gas	0.0000	0.0000		
	[GJH2/GJ]	Commercial Electricity	0.0000	0.0000		
	[GJH2/GJ]	Industrial Electricity	#NAME?	#NAME?		
	[GJH2/GJFeedstock]	Utility Steam Coal (Central)	0.0000	0.0000		
	[GJH2/GJFeedstock]	Diesel Fuel	0.0000	0.0000		
	[GJH2/GJFeedstock]	Biomass	0.0000	0.0000		
	[GJH2/GJFeedstock]	Ethanol	0.0000	0.0000		
	[GJH2/GJFeedstock]	Methanol	0.0000	0.0000		
	[GJH2/GJFeedstock]	Gasoline	0.0000	0.0000		
	[GJH2/GJFeedstock]	Steam	0.0000	0.0000		
	[GJH2-L]	Cooling Water	0.0000	0.0000		
	[GJH2-L]	Demineralized Water	0.0000	0.0000		
	[GJH2-L]	Process Water	0.0000	0.0000		
	[GJH2/Barrel]	Bio-oil	0.0000	0.0000		
	[GJH2/GJFeedstock]	ity Steam Coal (Regional)	0.0000	0.0000		
	[GJH2/GJFeedstock]	MSW (1)	0.0000	0.0000		
	[GJH2/GJFeedstock]	MSW (2)	0.0000	0.0000		
Var/Nearest Data	OtherVariableOM	[\$/kgH2]	(PY,CY)	2020	2050	
End				1	\$0.0000	\$0.0000
Var/Nearest Data	ByproductEfficiency		(Byproduct,CY)	2020	2050	
	[GJH2/GJ]	Byproduct Electricity	0.0000	0.0000		
End				Steam	0.0000	0.0000
Var/Nearest Data	Emissions	[kg/kgH2]	(Species,CY)	2020	2050	
		Carbon	0	0		
		GHG Equivalents	0	0		
		NOx	0	0		
		SOx	0	0		
		Particulates (PM10)	0	0		
		Mercury	0	0		
End						
Var/Nearest Data	ReplacementCosts	[\$]	(PY,CY)	2020	2050	
End				1	\$0.00	\$0.00
				20	\$0.00	\$0.00

0	Variable	[Units]	(y-axis, x-axis)	Data	Source Used
Var/Data	iClass			[2,2,-3,1]	
Var/Data	OClass			[3,3,-2]	
Var/Data	CYStart	[Year]		2020	
Var/Data	CYStop	[Year]		2050	
Axis	CY	CY		[2020,2050]	
Var/Data	IRR	[%]		10%	3
Var/Data	DepreciationLength	[Years]		15	3
Var/Data	AnalysisPeriod	[Years]		20	
Var/Data	Life	[Years]		20	3
Axis	PY	PY		[1,20]	
	DesignCapacity	[kgH2/day]		316,289	
Input	DesignCapacity	[kgH2/day]		115,445,485	
Input	CapacityFactor	[% of DesignCapacity]		90%	
Var/Data	Location			4	
	AverageCapacity	[kgH2/day]		284,660	
	Distance	[mi]		1000	
Input			(Component)	2020 2050	
		[deg. C]	Temperature	25 25	3
		[atm]	Pressure	20 20	3
Transmission Pipeline					
		(Component,CY)			
	Is a pipeline used?	1=yes, 2=no		1 1	
		[deg. C]	Temperature	25 25	3
		[atm]	Input Pressure	68 68	3
		[atm]	Output Pressure	48 48	3
			Compressibility Factor	#NAME? #NAME?	
		[kgH2/day]	Design Flowrate	316,289 316,289	
		[mi]	Length	1000 1000	
		[in]	Diameter	#NAME? #NAME?	
		[\$] (ea.)	Overhead, Pipeline Material	\$35,000 \$35,000	?
		[\$] (ea.)	Overhead, Miscellaneous	\$95,000 \$95,000	?
		[\$] (ea.)	Overhead, Labor	\$185,000 \$185,000	?
		[\$] (ea.)	Overhead, ROW	\$40,000 \$40,000	?
		[\$] (ea.)	Overhead, Pipeline TOTAL	\$355,000 \$355,000	
		[% of Pipeline Cost]	Pipeline Cost Factor	110% 110%	?
		[\$/mi]	Unit Cost, Pipeline Material	#NAME? #NAME?	
		[\$/mi]	Unit Cost, Miscellaneous	#NAME? #NAME?	
		[\$/mi]	Unit Cost, Labor	#NAME? #NAME?	
		[\$/mi]	Unit Cost, ROW	#NAME? #NAME?	
		[\$/mi]	Unit Cost, Pipeline TOTAL	#NAME? #NAME?	
		[\$]	Total Pipeline cost	#NAME? #NAME?	
Pipeline Compressors					
		(Component,CY)			
		[#]	Compressibility Factor	#NAME? #NAME?	
		[#]	(total) Quantity	2 2	5
		[#]	(needed) Quantity	2 2	3
		[kgH2/day] (ea.)	Design Flowrate	158,145 158,145	
		[kgH2/day] (ea.)	Average Flowrate	142,330 142,330	
		[#]	Pressure Ratio/Stage	1.7 1.7	3
		[#]	Stages	3 3	
		[%]	Efficiency	80% 80%	3
		[kW] (ea.)	Peak Power Req'd	#NAME? #NAME?	
		[kW] (ea.)	Average Power Req'd	#NAME? #NAME?	
		[kWh/kgH2]	e Energy Req'd (all plants)	#NAME? #NAME?	
		[% of Gas Compr. Cost]	Compressor Cost Factor	80% 80%	1
		[\$]	Pipeline Compressors	#NAME? #NAME?	
Cryo-Cooler					
		(Component)			
	Is there a Cryo-Cooler?	1=Yes, 2=No		1 1	
		[kgH2/day]	Max size of cry-cooler	100,000 100,000	10
		[#]	Number Plant Required	4 4	
		[kgH2/day]	Design Flow Rate	79,072.25 79,072.25	
		[%]	Average % Utilization	100% 100%	11
		[deg. C]	Exit Temp	-193.15 -193.15	11
		[atm]	Exit Pressure	20 20	11
		[%]	% (relative to full liq. Plant)	50% 50%	11
		[%]	% (relative to full liq. Plant)	40% 40%	5
		[kWh/kgH2]	e Energy Req'd (all plants)	4.07 4.07	
		[kWh/kgH2]	e Energy Req'd (all plants)	4.07 4.07	
		[\$]	tal Capital Cost (all plants)	168,368,823 168,368,823	
Storage Compressors					
		(Component)			
		[#]	H2 Compressibility Factor	#NAME? #NAME?	
		[#]	(total) Quantity	1 1	5
		[#]	(needed) Quantity	1 1	5
		[kgH2/day] (ea.)	Flowrate of each compr.	316,289 316,289	
		[%]	Average % Utilization	100% 100%	3
		[kgH2/day] (ea.)	Average Flowrate	316,289 316,289	
		[#]	Max Pressure Ratio/Stage	1.7 1.7	3
		[#]	Stages	4 4	
		[%]	Efficiency	80% 80%	3
		[deg. C]	Inlet Temperature	-193 -193	3
		[atm]	Min. Inlet pressure	20 20	3
		[atm]	Average Inlet pressure	20 20	3
		[atm]	Average Outlet pressure	68 68	5
		[atm]	Peak Outlet pressure	136 136	5
		[kW] (ea.)	Peak Power Req'd	#NAME? #NAME?	
		[kW] (ea.)	Average Power Req'd	#NAME? #NAME?	
		[kWh/kgH2 of aver. Plant]	e Energy Req'd (all plants)	#NAME? #NAME?	
		[% of Gas Compr. Cost]	Compressor Cost Factor	80% 80%	1
		[\$]	Storage Compressors	#NAME? #NAME?	
Buffer Storage, GH2					
		(Component)			
		[deg. C]	Inlet Temperature	-193.15 -193.15	11
		[atm]	Minimum Pressure	20 20	3
		[atm]	Average Pressure	68.0 68.0	3
		[atm]	Maximum Pressure	136.1 136.1	11
		[days]	Stor. at Plant max flow	0.333 0.333	6
		[kgH2]	Design Capacity	105,430 105,430	
		[m2]	Land Req'd	17,314 17,314	3
		[\$/kgH2]	Storage (at max pressure)	\$355.00 \$355.00	4
		[\$]	Storage	\$41,170,285 \$41,170,285	
Truck					
		(Component)			
		[atm]	Maximum Pressure	136 136	11
		[kgH2] (ea.)	Trailer Capacity	2100 2100	11
Truck Compressors					
		(Component)			
	Is there a Truck Gas Comp	1=Yes, 2=No		1 1	
		[#]	Compressibility Factor	#NAME? #NAME?	
		[#]	(total) Quantity	2 2	1
		[#]	(needed) Quantity	2 2	1
		[kgH2/day] (ea.)	Design Flowrate	158,145 158,145	
		[kgH2/day] (ea.)	Average Flowrate	142,330 142,330	
		[#]	Max Pressure Ratio/Stage	1.7 1.7	3
		[#]	Stages	4 4	
		[%]	Efficiency	80% 80%	1
		[deg. C]	Inlet Temperature	-193.15 -193.15	11
		[atm]	Min Inlet pressure	20.0 20.0	3
		[atm]	Average Inlet pressure	68.0 68.0	3
		[atm]	Average Outlet pressure	136.0 136.0	3
		[atm]	Peak Outlet pressure	136.0 136.0	3
		[kW] (ea.)	Peak Power Req'd	#NAME? #NAME?	
		[kW] (ea.)	Average Power Req'd	#NAME? #NAME?	
		[kWh/kgH2 of aver. Plant]	e Energy Req'd (all plants)	#NAME? #NAME?	
		[% of Gas Compr. Cost]	Compressor Cost Factor	80% 80%	1
		[\$]	Truck Compressors	#NAME? #NAME?	
Terminal Bays					
		(Component)			
		[#] (day) (maximum)	Pick-up Limit	151 151	
		[hours]	(filling) Time/Pick-up	2 2	11
		[hours]	(non-filling) Time/Pick-up	1 1	11
		[#]	Bays	19 19	
		[m]	Bay Width	5 5	3
		[m/Bay]	Header Length	5 5	
		[m]	Compr. to Header Length	30 30	3
		[m]	Storage to Compr. Length	30 30	3
		[m2]	Land Req'd	8,246 8,246	
		[\$/Bay]	Unit Cost, Bays	\$10,000.00 \$10,000.00	3
		[\$]	Bays	\$190,000.00 \$190,000.00	
Liquefiers					
		(Component)			
		[%]	Liq. Size % of prod. Plant	10% 10%	5
		[kgH2/day] (total)	red Max Total Liq.Flowrate	31,629 31,629	

julie_perez:
Adjusted to 40% to mimic the improvement in electricity consumption in liquefiers in 2025.

brian_james:
Used to calculated design flow rate of compressor.

brian_james:
Peak elec. Power used of capital cost estimation.
Average elec. Power used of electricity cost computation.

brian_james:
Peak elec. Power used of capital cost estimation.
Average elec. Power used of electricity cost computation.

julie_perez:
Corrected equation from H2A so that ratio is of buffer design capacity to trailer design capacity.

brian_james:
Includes 10% installation factor.

brian_james:
Used to calculated design flow rate of compressor.

brian_james:
Time to actually pump/transfer H2 into the trucks.

brian_james:
Time to connect hoses, drive truck to bay, etc.

Plumbing, electrical and instrumentation

	[kgH2/day]	Liquifier Flowrate Limit	100,000	100,000	10	
	[#]	Quantity	1	1		
	[kgH2/day] (ea.)	Design Flowrate	31,629	31,629		
	[%]	Average % Utilization	50%	50%	5	brian_james: Energy per kgH2 computed at full utilization.
	[kgH2/day] (ea.)	Average Flowrate	15,814	15,814		
	[m2]	Land Req'd	17,025	17,025		
	[kWh/kgH2 of LH2]	Average Energy Req'd	12.17	12.17		julie_perez: Corrected Learning to Cumulative Average Theory. 10 Apr 2007.
	kW	Average Power Req'd	8,020	8,020		
	[kWh/kgH2 of aver. Plant cte Energy Req'd (all plants)]		0.68	0.68		
	[\$]	Liquifier Cost	\$52,132,561	\$52,132,561		
		Learning Factor	0.9	0.9	5	
LH2 Outage Storage		(Component)				
	[% Lique storage vol.]	Usable Capacity	90%	90%	3	
	[#]	ays of full Plant Production	5	5	3	
	[kgH2]	Storage Design Capacity	1,757,161	1,757,161		
	[m2]	Land Req'd	2,057	2,057		
	[\$]	LH2 Storage Cost	\$57,222,272	\$57,222,272	3	
LH2 Evaporator		(Component)				
	Is there a LH2-Evap.?	1=Yes, 2=No	2	2		
	%	Evap Flow Rate (% of total	100%	100%	5	Plumbing, electrical and instrumentation
	[kgH2/day]	Evap Design Flow Rate	316,289	\$16,289		
	[\$]	Evaporator Cost	\$0	\$0	3	
Terminal (LH2 Pumps)		(Component)				
	[kgH2/hr] (total)	(system) Req'd Flowrate	19,768	19,768		
	[% of Req'd Flowrate]	Factor of Safety	50%	50%	3	
	[#]	Quantity	2	2	3	
	[kgH2/hour] (ea.)	Design Flowrate	14,826	14,826		
	[\$/kgH2/hr]	Unit Cost, Pumps	\$150.00	\$150.00	3	
	[\$]	LH2 Pump Cost	\$4,447,814	\$4,447,814		
Costs						
DepreciableCapital (Direct)		(Component)				
	[\$]	Transmission Pipeline	#NAME?	#NAME?		
	[\$]	Pipeline Compressors	#NAME?	#NAME?		
	[\$]	Cryo-Cooler	\$168,368,823	\$168,368,823		
	[\$]	Storage Compressors	#NAME?	#NAME?		
	[\$]	Buffer Storage	\$41,170,285	\$41,170,285		brian_james: Liquifier and storage only. (No pipeline land included.)
	[\$]	Truck Compressors	#NAME?	#NAME?		
	[\$/m]	Unit Cost, Piping	\$300	\$300	3	
	[\$]	Piping	\$46,500	\$46,500		
	[\$]	Bays	\$190,000	\$190,000		
	[\$]	Buildings and Structures	\$50,000	\$50,000	3	
	[\$]	Truck Scale	\$80,000	\$80,000	3	julie_perez: 20% is the NDA Standard.
	[\$]	Liquifiers	\$52,132,561	\$52,132,561		
	[\$]	LH2 Storage	\$57,222,272	\$57,222,272		
	[\$]	LH2 Evaporator	\$0	\$0		
	[\$]	LH2 Pumps	\$4,447,814	\$4,447,814		
	[\$]	Installed Costs	#NAME?	#NAME?		
DepreciableCapital (Indirect)		(Component)				
	[% of Installed Costs]	Site Preparation	12%		3	
	[% of Installed Costs]	Engineering & Design	32%		3	
	[\$]	Process Contingency	\$0.00			
	[% of Installed Costs]	Project Contingency	25%		3	
	[\$]	Other Depreciable Capital	\$0.00			
	[% of Installed Costs]	One-Time Licensing Fees	1.5%		3	
	[% of Installed Costs]	Up-Front Permitting Costs	4%		3	
Var/Nearest Data	DepreciableCapital	[\$]	(CY)	2020	2050	
Var/Data	LandRequired	[acres]		#NAME?	#NAME?	
FixedOM		(Component)				
	[hours/year]	Labor Req'd	17,520		3	
	[\$/hour]	Labor Costs	\$24.20		3	
	[\$/year]	Labor Costs	\$423,984.00			
	[% of Labor]	Overhead and O&A	20%		5	
	[% of DepreciableCapital]	Property Tax & Insurance	2.5%		3	
	[\$/year]	Rent	\$0.00			
	[\$/year]	Lic., Permits and Fees	\$0.00		5	
	[% of Installed Costs]	Matt for Maint. & Repairs	0.5%		3	
	[\$/year]	Other Fees	\$0.00		3	
	[\$/year]	Other Fixed O&M Costs	\$0.00			
Var/Nearest Data	FixedOM	[\$/year]	(PY,CY)	2020	2050	
End			1	#NAME?	#NAME?	
Var/Nearest Data	OtherFixed	[\$/year]	(PY,CY)	2020	2050	
End			1	\$0.00	\$0.00	
Var/Nearest Data	FeedstockEfficiency		(Feedstock,CY)	2020	2050	
	[GJH2/GJFeedstock]	Commercial Natural Gas	0.0000	0.0000		
	[GJH2/GJFeedstock]	Industrial Natural Gas	0.0000	0.0000		
	[GJH2/GJFeedstock]	Electric Utility Natural Gas	0.0000	0.0000		
	[GJH2/GJ]	Commercial Electricity	0.0000	0.0000		
	[GJH2/GJ]	Industrial Electricity	#NAME?	#NAME?		
	[GJH2/GJFeedstock]	Utility Steam Coal (Central)	0.0000	0.0000		
	[GJH2/GJFeedstock]	Diesel Fuel	0.0000	0.0000		
	[GJH2/GJFeedstock]	Biomass	0.0000	0.0000		
	[GJH2/GJFeedstock]	Ethanol	0.0000	0.0000		
	[GJH2/GJFeedstock]	Methanol	0.0000	0.0000		
	[GJH2/GJFeedstock]	Gasoline	0.0000	0.0000		
	[GJH2/GJFeedstock]	Steam	0.0000	0.0000		
	[GJH2-L]	Cooling Water	0.0000	0.0000		
	[GJH2-L]	Deminerlized Water	0.0000	0.0000		
	[GJH2-L]	Process Water	0.0000	0.0000		
	[GJH2/Barrel]	Bio-oil	0.0000	0.0000		
	[GJH2/GJFeedstock]	ity Steam Coal (Regional)	0.0000	0.0000		
	[GJH2/GJFeedstock]	MSW (1)	0.0000	0.0000		
	[GJH2/GJFeedstock]	MSW (2)	0.0000	0.0000		
Var/Nearest Data	OtherVariableOM	[\$/kgH2]	(PY,CY)	2020	2050	
End			1	\$0.0000	\$0.0000	
Var/Nearest Data	ByproductEfficiency		(Byproduct,CY)	2020	2050	
	[GJH2/GJ]	Byproduct Electricity	0.0000	0.0000		
	[GJH2/GJFeedstock]	Steam	0.0000	0.0000		
Var/Nearest Data	Emissions	[kg/kgH2]	(Species,CY)	2020	2050	
		Carbon	0	0		
		GHG Equivalents	0	0		
		NOX	0	0		
		SOX	0	0		
		Particulates (PM10)	0	0		
		Mercury	0	0		
End						
Var/Nearest Data	ReplacementCosts	[\$]	(PY,CY)	2020	2050	
End			1	\$0.00	\$0.00	
			20	\$0.00	\$0.00	

0	Variable	[Units]	(y-axis,x-axis)	Data	Source Used
VarData	IClass			[3,1,-2,1]	
VarData	OClass			[4,1,1]	
VarData	CYStart	[Year]		2005	
VarData	CYStop	[Year]		2050	
Axis	CY	CY		[2005-2050]	
VarData	IRR	[%]		10%	3
VarData	DepreciationLength	[Years]		5	3
VarData	AnalysisPeriod	[Years]		20	
VarData	Life	[Years]		20	3
Axis	PY	PY		[1-20]	
Input	Location			5	
	Dist. to CG	[mi]		346	
	Dist. to Station	[mi] (total from Plant)		380.034	
	Engineering Assumptions	(Component)			
	Temperature	(deg. C)		25	3
	Maximum Pressure	[atm]		180	3
	Minimum Pressure	[atm]		15	3
	Trailer Volume	[m3]		23.4	3
	Trailer Capacity	[kgH2]		280	
	Time/Drop-off @ Sta.	[hours]		1.5	3
	(filling) Time/Pick-up @ Ter.			6	3
	(non-filling) Time/Pick-up @ Ter.			1.5	3
	Average Speed	[mi/hour]		30	3
	Time/Trip	[hours]		28.33561976	
	Trips	[t/day] (maximum)		0.4	
	Trailers/Tractor	[#]		1.21	
	Availability	[%/year]		98%	3
	Fuel Efficiency	[mi/gal]		6	3
VarData	DesignCapacity	[kgH2/year]		43,333	
VarData	CapacityFactor	[% of DesignCapacity]		69%	
	Costs				
	DepreciableCapital (Direct)	(Component)			
	Unit Cost, Tractor	[\$]		\$75,000.00	10
	Unit Cost, Trailer	[\$]		\$225,000.00	10
VarLinear	DepreciableCapital	[\$] (ea.)		(CY) 2005 2050	
Data				\$347,643.21 \$347,643.21	
VarData	LandRequired	[acres]		0	
VarLinear	FixedOM	[\$/year]		(PY,CY) 2005 2050	
Data				1 \$0.00 \$0.00	
End				20 \$0.00 \$0.00	
VarLinear	OtherFixed	[\$/year]		(PY,CY) 2005 2050	
Data				1 \$0.00 \$0.00	
End				20 \$0.00 \$0.00	
VarLinear	FeedstockEfficiency			(Feedstock,CY) 2005 2050	
Data	[GJH2/GJFeedstock]			Commercial Natural Gas 0.0000 0.0000	
	[GJH2/GJFeedstock]			Industrial Natural Gas 0.0000 0.0000	
	[GJH2/GJFeedstock]			Electric Utility Natural Gas 0.0000 0.0000	
	[GJH2/GJ]			Commercial Electricity 0.0000 0.0000	
	[GJH2/GJ]			Industrial Electricity 0.0000 0.0000	
	[GJH2/GJFeedstock]			Utility Steam Coal (Central) 0.0000	
	[GJH2/GJFeedstock]			Diesel Fuel 1.9834 1.9834	
	[GJH2/GJFeedstock]			Biomass 0.0000 0.0000	
	[GJH2/GJFeedstock]			Ethanol 0.0000 0.0000	
	[GJH2/GJFeedstock]			Methanol 0.0000 0.0000	
	[GJH2/GJFeedstock]			Gasoline 0.0000 0.0000	
	[GJH2/GJFeedstock]			Steam 0.0000 0.0000	
	[GJH2/L]			Cooling Water 0.0000 0.0000	
	[GJH2/L]			Deminerlized Water 0.0000 0.0000	
	[GJH2/L]			Process Water 0.0000 0.0000	
	[GJH2/Barrel]			Bio-oil 0.0000 0.0000	
	[GJH2/GJFeedstock]			ity Steam Coal (Regional) 0.0000 0.0000	
	[GJH2/GJFeedstock]			MSW (1) 0.0000 0.0000	
	[GJH2/GJFeedstock]			MSW (2) 0.0000 0.0000	
End	OtherVariableOM			(Component)	
	[hours/kgH2]			Labor Req'd 0.1011	
	[\$/hour]			Labor Costs \$40.00	
	[\$/kgH2]			Labor Costs \$4.043	
	[% of Labor]			Overhead and G&A 20%	
	[\$/mi]			Property Tax & Insurance \$0.102	
	[\$/kgH2]			Property Tax & Insurance \$0.277	
	[\$/mi]			Lic., Permits and Fees \$0.112	
	[\$/kgH2]			Lic., Permits and Fees \$0.304	
	[\$/mi]			Martl for Maint. & Repairs \$0.075	
	[\$/kgH2]			Martl for Maint. & Repairs \$0.203	
	[\$/year] @ capacity			Other Variable Op. Costs \$0.00	
VarLinear	OtherVariableOM	[\$/kgH2]		(PY,CY) 2005 2050	
Data				1 \$5.64 \$5.64	
End				20 \$5.64 \$5.64	
VarLinear	ByproductEfficiency			(Byproduct,CY) 2005 2050	
Data	[GJH2/GJ]			Byproduct Electricity 0.0000 0.0000	
End				Steam 0.0000 0.0000	
VarLinear	Emissions	[t/kgH2]		(Species,CY) 2005 2050	
Data				Carbon 0 0	
				GHG Equivalents 0 0	
				NOX 0 0	
				SOX 0 0	
				Particulates (PM10) 0 0	
				Mercury 0 0	
End	ReplacementCosts	[\$]		(PY,CY) 2005 2050	
VarLinear				1 \$0.00 \$0.00	
Data				5 \$0.00 \$0.00	
				6 \$75,000.00 \$75,000.00	
				7 \$0.00 \$0.00	
				10 \$0.00 \$0.00	
				11 \$75,000.00 \$75,000.00	
				12 \$0.00 \$0.00	
				15 \$0.00 \$0.00	
				16 \$75,000.00 \$75,000.00	
				17 \$0.00 \$0.00	
End				20 \$0.00 \$0.00	

0.5 hr for dropoff + 1.0 hr for pickup

Julie_perez:
24/2 is 12 hrs which is the number of hrs truck is able to deliver due to transportation/ road permit limitations.

This is just the # of extra trailers needed beyond 1/station. The error incurred by not constraining this to be an integer is 0-3 trailers (independent of total # of tractors). Also, H2Sim only tracks tractors (not trailers). Therefore, if a tractor is re-assigned from C->CG, any additional trailers needed will seem to appear out of nowhere. Likewise, if a tractor is re-assigned from CG->C, any excess trailers will disappear, lowering tax benefits from depreciation!

Julie_perez:
H2A Costs of \$20/hr seem too low. Confirmed with APCI.

100% to tractor

100% to tractor. 20% is H2A Standard

75% to tractor

50% to tractor

75% to tractor

Life of Tractor is 5 years

Life of Tractor is 5 years

Life of Tractor is 5 years

0	Variable	[Units]	(y-axis,x-axis)	Data	Source Used
VarData	IClass			[3,3,-2,1]	
VarData	OClass			[4,3,1]	
VarData	CYStart	[Year]		2020	
VarData	CYStop	[Year]		2050	
Axis	CY	CY		[2020-2050]	
VarData	IRR	[%]		10%	3
VarData	DepreciationLength	[Years]		5	5
VarData	AnalysisPeriod	[Years]		20	
VarData	Life	[Years]		20	
Axis	PY	PY		[1-20]	3
Input	Location			5	
	Dist. to CG	[mi]		346	
	Dist. to Station	[mi] (total from Plant)		380.034	
	Engineering Assumptions	(Component)			
		(deg. C)		25	11
		[atm]		136	11
		[atm]		15	5
		[m3]		23	11
		[kgH2]		2100	11
		[hours]		1.5	5
		(filling) Time/Pick-up @ Ter.		2	3
		(non-filling) Time/Pick-up @ Ter.		1	3
		[mi/hour]		30	3
		[hours]		27.83561976	5
		[t/day] (maximum)		0.4	5
		[t]		1.07	5
		Availability		98%	3
		Fuel Efficiency		5	3
VarData	DesignCapacity	[kgH2/year]		330,440	
VarData	CapacityFactor	[% of DesignCapacity]		69%	
	Costs				
	DepreciableCapital (Direct)	(Component,CY)			
		Unit Cost, Tractor		\$75,000.00	10
		Unit Cost, Trailer		\$745,000.00	11
VarLinear	DepreciableCapital	(\$)			
Data		(\$) (ea.)			
VarData		(CY)		2020 2050	
VarData				\$873,528.54 \$873,528.54	
VarLinear	LandRequired	[acres]			
Data				0 0	
VarData	FixedOM	(\$/year)			
End		(PY,CY)		2020 2050	
VarLinear				1 \$0.00 \$0.00	
Data				20 \$0.00 \$0.00	
VarLinear	OtherFixed	(\$/year)			
End		(PY,CY)		2020 2050	
VarLinear				1 \$0.00 \$0.00	
Data				20 \$0.00 \$0.00	
VarLinear	FeedstockEfficiency				
Data		(Feedstock,CY)		2020 2050	
	[GJH2/GJFeedstock]	Commercial Natural Gas		0.0000 0.0000	
	[GJH2/GJFeedstock]	Industrial Natural Gas		0.0000 0.0000	
	[GJH2/GJFeedstock]	Electric Utility Natural Gas		0.0000 0.0000	
	[GJH2/GJ]	Commercial Electricity		0.0000 0.0000	
	[GJH2/GJ]	Industrial Electricity		0.0000 0.0000	
	[GJH2/GJFeedstock]	Utility Steam Coal (Central)		0.0000 0.0000	
	[GJH2/GJFeedstock]	Diesel Fuel		14.8580 14.8580	
	[GJH2/GJFeedstock]	Biomass		0.0000 0.0000	
	[GJH2/GJFeedstock]	Ethanol		0.0000 0.0000	
	[GJH2/GJFeedstock]	Methanol		0.0000 0.0000	
	[GJH2/GJFeedstock]	Gasoline		0.0000 0.0000	
	[GJH2/GJFeedstock]	Steam		0.0000 0.0000	
	[GJH2/L]	Cooling Water		0.0000 0.0000	
	[GJH2/L]	Demineralized Water		0.0000 0.0000	
	[GJH2/L]	Process Water		0.0000 0.0000	
	[GJH2/Barrel]	Bio-oil		0.0000 0.0000	
	[GJH2/GJFeedstock]	Utility Steam Coal (Regional)		0.0000 0.0000	
	[GJH2/GJFeedstock]	MSW (1)		0.0000 0.0000	
	[GJH2/GJFeedstock]	MSW (2)		0.0000 0.0000	
End	OtherVariableOM	(Component)			
	[hours/kgH2]	Labor Req'd		0.0133	5
	[\$/hour]	Labor Costs		\$40.00	5
	[\$/kgH2]	Labor Costs		\$0.53	5
	[% of Labor]	Overhead and G&A		20%	5
	[\$/mi]	Property Tax & Insurance		\$0.102	3
	[\$/kgH2]	Property Tax & Insurance		\$0.037	3
	[\$/mi]	Lic., Permits and Fees		\$0.112	3
	[\$/kgH2]	Lic., Permits and Fees		\$0.041	3
	[\$/mi]	Mart for Maint. & Repairs		\$0.075	3
	[\$/kgH2]	Mart for Maint. & Repairs		\$0.027	3
	[\$/year] @ capacity	Other Variable Op. Costs		\$0.00	5
VarLinear	OtherVariableOM	(\$/kgH2)			
Data		(PY,CY)		2020 2050	
End				1 \$0.74 \$0.74	
VarLinear	ByproductEfficiency				
Data		(Byproduct,CY)		2020 2050	
End				1 \$0.74 \$0.74	
VarLinear	Emissions	[kg/kgH2]			
Data		(Species,CY)		2020 2050	
		Carbon		0 0	
		GHG Equivalents		0 0	
		NOX		0 0	
		SOX		0 0	
		Particulates (PM10)		0 0	
		Mercury		0 0	
End	ReplacementCosts	(\$)			
VarLinear		(PY,CY)		2020 2050	
Data				1 \$0.00 \$0.00	
				5 \$0.00 \$0.00	
				6 \$75,000.00 \$75,000.00	3
				7 \$0.00 \$0.00	
				10 \$0.00 \$0.00	
				11 \$75,000.00 \$75,000.00	3
				12 \$0.00 \$0.00	
				15 \$0.00 \$0.00	
				16 \$75,000.00 \$75,000.00	3
				17 \$0.00 \$0.00	
				20 \$0.00 \$0.00	

Although not used below, Temperature, Maximum Pressure and Minimum Pressure are referenced by other tabs.

Julie_perez:
Based on comments provided by B. Bonner of APCI on 6 Oct 2006.

Referenced Liquid Truck.

Referenced Liquid Truck.

Julie_perez:
24/2 is 12 hrs which is the number of hrs truck is able to deliver due to transportation road permit limitations.

This is just the # of extra trailers needed beyond 1 station. The error incurred by not constraining this to be an integer is 0-3 trailers (independent of total # of tractors). Also, H2Sim only tracks tractors (not trailers). Therefore, if a tractor is re-assigned from C->CG, any additional trailers needed will seem to appear out of nowhere; likewise, if a tractor is re-assigned from CG->C, any excess trailers will disappear, lowering tax benefits from depreciation!

Julie_perez:
H2A Costs of \$20/hr seem too low. Confirmed with APCI.

100% to tractor

100% to tractor. 20% is the H2A standard

75% to tractor

50% to tractor

75% to tractor

Life of Tractor is 5 years

Life of Tractor is 5 years

Life of Tractor is 5 years

Delivery: LT to 0.1TPD

LT to 0.1TPD

Variable	[Units]	(y-axis,x-axis)	Data	Source Used		
VarData	IClass		[3,4,-2,2]			
VarData	OClass		[4,5,1]			
VarData	CYStart	[Year]	2005			
VarData	CYStop	[Year]	2050			
Axis	CY		[2005-2050]			
VarData	IRR	[%]	10%	3		
VarData	DepreciationLength	[Years]	5	3		
VarData	AnalysisPeriod	[Years]	20			
VarData	Life	[Years]	20	3		
Axis	PY		[1-20]			
Input	Location		5			
	Dist. to CG	[mi]	346			
	Dist. to Station	[mi] (total from Plant)	380.034			
	Engineering Assumptions	(Component)				
		Trailer Volume	65	3		
		Usable Trailer Capacity	95%	10		
		Trailer Capacity	4,372 (ea.)			
		Stations/Trip	1	3		
		Time/Drop-off	3.5	3		
		(filling) Time/Pick-up	2	3		
		(non-filling) Time/Pick-up	1	5		
		Average Speed	30	3		
		Time/Trip	31.83561976			
		Trips	0.376936277			
		Trailers/Tractor	1	3		
		Availability	98%	3		
		Fuel Efficiency	6	3		
VarData	DesignCapacity	[kgH2/year]	601,543			
VarData	CapacityFactor	[% of DesignCapacity]	69%			
	Costs	(Component)				
	DepreciableCapital (Direct)					
		Unit Cost, Tractor	\$75,000.00	10		
		Unit Cost, Trailer	\$625,000.00	3		
VarLinear	DepreciableCapital	[\$] (ea.)				
Data		(CY)	2005 2050			
VarData	LandRequired	[acres]	0			
VarLinear	FixedOM	[\$/year]				
Data		(PY,CY)	2005 2050			
End			\$0.00 \$0.00			
VarLinear	OtherFixed	[\$/year]				
Data		(PY,CY)	2005 2050			
End			\$0.00 \$0.00			
VarLinear	FeedstockEfficiency					
Data		(Feedstock,CY)	2005 2050			
	(G,H ₂ ,G,JFeedstock)	Commercial Natural Gas	0.0000 0.0000			
	(G,H ₂ ,G,JFeedstock)	Industrial Natural Gas	0.0000 0.0000			
	(G,H ₂ ,G,JFeedstock)	Electric Utility Natural Gas	0.0000 0.0000			
	(G,H ₂ ,G,J)	Commercial Electricity	0.0000 0.0000			
	(G,H ₂ ,G,J)	Industrial Electricity	0.0000 0.0000			
	(G,H ₂ ,G,JFeedstock)	Utility Steam Coal (Central)	0.0000 0.0000			
	(G,H ₂ ,G,JFeedstock)	Diesel Fuel	30.9348			
	(G,H ₂ ,G,JFeedstock)	Biomass	0.0000 0.0000			
	(G,H ₂ ,G,JFeedstock)	Ethanol	0.0000 0.0000			
	(G,H ₂ ,G,JFeedstock)	Methanol	0.0000 0.0000			
	(G,H ₂ ,G,JFeedstock)	Gasoline	0.0000 0.0000			
	(G,H ₂ ,G,JFeedstock)	Steam	0.0000 0.0000			
	(G,H ₂ ,L)	Cooling Water	0.0000 0.0000			
	(G,H ₂ ,L)	Deminerlized Water	0.0000 0.0000			
	(G,H ₂ ,L)	Process Water	0.0000 0.0000			
	(G,H ₂ ,Barnel)	Bio-oil	0.0000 0.0000			
	(G,H ₂ ,G,JFeedstock)	ity Steam Coal (Regional)	0.0000 0.0000			
	(G,H ₂ ,G,JFeedstock)	MSW (1)	0.0000 0.0000			
	(G,H ₂ ,G,JFeedstock)	MSW (2)	0.0000 0.0000			
End						
	OtherVariableOM	(Component)				
		Labor Req'd	0.0073			
		Labor Costs	\$40.00	5		
		Labor Costs	\$0.29			
		Overhead and G&A	20%	5		
		Property Tax & Insurance	\$0.102	3		
		Property Tax & Insurance	\$0.018			
		Lic., Permits and Fees	\$0.112	3		
		Lic., Permits and Fees	\$0.019			
		Mart for Maint. & Repairs	\$0.075	3		
		Mart for Maint. & Repairs	\$0.013			
		Other Variable Op. Costs	\$0.000	5		
VarLinear	OtherVariableOM	[\$/kgH2]				
Data		(PY,CY)	2005 2050			
End			\$0.40 \$0.40			
VarLinear	ByproductEfficiency					
Data		(Byproduct,CY)	2005 2050			
End			0.0000 0.0000			
VarLinear	Emissions	[kg/kgH2]				
Data		(Species,CY)	2005 2050			
		Carbon	0 0			
		GHG Equivalents	0 0			
		NOX	0 0			
		SOX	0 0			
		Particulates (PM10)	0 0			
		Mercury	0 0			
End						
VarLinear	ReplacementCosts	[\$]				
Data		(PY,CY)	2005 2050			
		1	\$0.00 \$0.00			
		5	\$0.00 \$0.00			
		6	\$75,000.00 \$75,000.00			
		7	\$0.00 \$0.00			
		10	\$0.00 \$0.00			
		11	\$75,000.00 \$75,000.00			
		12	\$0.00 \$0.00			
		15	\$0.00 \$0.00			
		16	\$75,000.00 \$75,000.00			
		17	\$0.00 \$0.00			
		20	\$0.00 \$0.00			
End						
	LearningFactor		(Technology, Factor)			
			IClass[1] (L)	IClass[2] (L)	IClass[4] (L)	Factor
			LT (to 0.1TPD or 1.5TPD)			
			3	4	1	0.9999
	InitialUnitNo	[unit # in CYBegin]	1000			
	LearningFactorStart		0.999003868			

Assumes stations are co-located

julie_perez:
24/2 is 12 hrs which is the number of hrs truck is able to deliver due to transportation/ road permit limitations.

julie_perez:
HZA Costs of \$20/hr seem too low. Confirmed with APCL.

100% to tractor

100% to tractor. 20% is standard for HZA.

75% to tractor

50% to tractor

75% to tractor

Life of Tractor is 5 years

Life of Tractor is 5 years

Life of Tractor is 5 years

These cells are a reference to the "LT to 0.1TPD" page to ensure the #s stay the same

No delivery (1-3) sheets with the same 3 share a LearningFactor (e.g. LT to 0.1TPD and LT to 1.5TPD only need one LearningFactor, since both sheets represent the same underlying technology - LT). The L for this common factor should always be 1, and the factor should appear on every sheet that shares it

Assumes stations are co-located

Julie_perez:
24/2 is 12 hrs which is the number of hrs truck is able to deliver due to transportation/road permit limitations.

Julie_perez:
H2A Costs of \$20/hr seem too low. Confirmed with APCI.

100% to tractor

100% to tractor. 20% is standard for H2A.

75% to tractor

50% to tractor

75% to tractor

Life of Tractor is 5 years

Life of Tractor is 5 years

Life of Tractor is 5 years

These cells are a reference to the "LT to 0.1TPD" page to ensure the #s stay the same

All delivery (1-3) sheets with the same J share a LearningFactor (e.g., LT to 0.1TPD and LT to 1.5TPD only need one LearningFactor, since both sheets represent the same underlying technology - LTs). The L for this common factor should always be 1, and the factor should appear on every sheet that shares it.

-1	Variable	[Units]	(y-axis,x-axis)	Data	Source Used
Var/Data	IClass			[3,5,1,1]	
Var/Data	OClass			[4,6,1]	
Var/Data	CYStart	[Year]		2025	
Var/Data	CYStop	[Year]		2050	
Axis	CY	CY		[2025-2050]	
Var/Data	IRR	[%]		10%	3
Var/Data	DepreciationLength	[Years]		15	3
Var/Data	AnalysisPeriod	[Years]		20	
Var/Data	Life	[Years]		20	3
Axis	PY	PY		[1-20]	
Var/Data	DesignCapacity	[kgH2/day]		1,500	5
Var/Data	DesignCapacity	[kgH2/year]		\$47,500	
Var/Data	CapacityFactor	[% of DesignCapacity]		70%	3
Var/Data	AverageCapacity	[kgH2/day]		1050	
Var/Data	Location			3	
Engineering Assumptions					
Typical Pipeline Segment					
	(Component,CY)		2025	2050	
	(deg. C)	Temperature	25	25	3
	(atm)	Input Pressure	48	48	3
	(atm)	Output Pressure	20	20	3
		Compressibility Factor	1.0216	1.0216	
	(kgH2/day)	Design Flowrate	4,500	4,500	5
	(mi)	Length	8.6458	8.6458	
	(in)	Pipeline Diameter	1.326894033	1.326894033	
Costs					
DepreciableCapital (Direct)					
	(Component,CY)		2025	2050	
	(\$ (ea.))	Overhead, Pipeline Material	\$35,000.00	\$35,000.00	3
	(\$ (ea.))	Overhead, Miscellaneous	\$95,000.00	\$95,000.00	3
	(\$ (ea.))	Overhead, Labor	\$185,000.00	\$185,000.00	3
	(\$ (ea.))	Overhead, ROW	\$40,000.00	\$40,000.00	3
	(\$ (ea.))	Overhead, Pipeline TOTAL	\$355,000.00	\$355,000.00	
	[% of Pipeline Cost]	Pipeline Cost Factor	110%	110%	3
	(\$/mi)	Unit Cost, Pipeline Material	\$31,298.82	\$31,298.82	3
	(\$/mi)	Unit Cost, Miscellaneous	\$20,341.71	\$20,341.71	3
	(\$/mi)	Unit Cost, Labor	\$190,705.77	\$190,705.77	3
	(\$/mi)	Unit Cost, ROW	\$33,608.98	\$33,608.98	3
	(\$/mi)	Unit Cost, Pipeline TOTAL	\$275,955.28	\$275,955.28	
DepreciableCapital (Indirect)					
	(Component,CY)		2025	2050	
Var/Linear	DepreciableCapital	(\$ (ea.))	(PY,CY)	2025	2050
Data			1	\$355,000.00	\$355,000.00
End			20	\$355,000.00	\$355,000.00
Var/Linear	DepreciableCapitalPer	(\$ (/mile))	(PY,CY)	2025	2050
Data			1	\$275,955.28	\$275,955.28
End			20	\$275,955.28	\$275,955.28
Var/Data	LandRequired	(acres)		0	
FixedOM					
	(Component)				
	(hours/year)	Labor Req'd	8,230		3
	(\$/hour)	Labor Costs	\$15.05		3
	(\$/year)	Labor Costs	\$123,861.50		
	[% of Labor]	Overhead and G&A	20%		5
	[% of DepreciableCapital]	Property Tax & Insurance	2.5%		3
	(\$/year)	Rent	\$0.00		
	[% of Installed Costs]	Lic., Permits and Fees	1.0%		3
	[% of Installed Costs]	Mort for Maint. & Repairs	0.5%		3
	(\$/year)	Other Fees	\$0.00		3
	(\$/year)	Other Fixed O&M Costs	\$0.00		3
Var/Linear	FixedOM	(\$/year) (ea.)	(PY,CY)	2025	2050
Data			1	\$14,200.00	\$14,200.00
End			20	\$14,200.00	\$14,200.00
Var/Linear	FixedOMPerMile	(\$/year) (/mile)	(PY,CY)	2025	2050
Data			1	\$11,038.21	\$11,038.21
End			20	\$11,038.21	\$11,038.21
Var/Linear	FixedOMOverall	(\$/year) (overall)	(CY)	2025	2050
Data				\$148,633.82	\$148,633.82
Var/Linear	OtherFixed	(\$/year) (ea.)	(PY,CY)	2025	2050
Data			1	\$0.00	\$0.00
End			20	\$0.00	\$0.00
Var/Linear	FeedstockEfficiency		(Feedstock,CY)	2025	2050
Data					
	(GJH2/GJFeedstock)	Commercial Natural Gas	0.0000	0.0000	
	(GJH2/GJFeedstock)	Industrial Natural Gas	0.0000	0.0000	
	(GJH2/GJFeedstock)	Electric Utility Natural Gas	0.0000	0.0000	
	(GJH2/GJ)	Commercial Electricity	0.0000	0.0000	
	(GJH2/GJ)	Industrial Electricity	0.0000	0.0000	
	(GJH2/GJFeedstock)	Jilliy Steam Coal (Central)	0.0000	0.0000	
	(GJH2/GJFeedstock)	Diesel Fuel	0.0000	0.0000	
	(GJH2/GJFeedstock)	Biomass	0.0000	0.0000	
	(GJH2/GJFeedstock)	Ethanol	0.0000	0.0000	
	(GJH2/GJFeedstock)	Methanol	0.0000	0.0000	
	(GJH2/GJFeedstock)	Gasoline	0.0000	0.0000	
	(GJH2/GJFeedstock)	Steam	0.0000	0.0000	
	(GJH2/L)	Cooling Water	0.0000	0.0000	
	(GJH2/L)	Deminerlized Water	0.0000	0.0000	
	(GJH2/L)	Process Water	0.0000	0.0000	
	(GJH2/Barrel)	Bio-oil	0.0000	0.0000	
	(GJH2/GJFeedstock)	lity Steam Coal (Regional)	0.0000	0.0000	
	(GJH2/GJFeedstock)	MSW (1)	0.0000	0.0000	
	(GJH2/GJFeedstock)	MSW (2)	0.0000	0.0000	
End	OtherVariableOM	(\$/kgH2)	(PY,CY)	2025	2050
Var/Linear			1	\$0.0000	\$0.0000
Data			20	\$0.0000	\$0.0000
End					
Var/Linear	ByproductEfficiency		(Byproduct,CY)	2025	2050
Data					
	(GJH2/GJ)	Byproduct Electricity	0.0000	0.0000	
End					
Var/Linear	Emissions	(kg/kgH2)	(Species,CY)	2025	2050
Data					
		Carbon	0	0	
		GHG Equivalents	0	0	
		NOX	0	0	
		SOX	0	0	
		Particulates (PM10)	0	0	
		Mercury	0	0	
End	ReplacementCosts	(\$ (ea.))	(PY,CY)	2025	2050
Var/Linear			1	\$0.00	\$0.00
Data			20	\$0.00	\$0.00
End					

This is currently set to MinStationSpacing times a circuitly factor
This is the **WORST CASE** length of pipeline needed in the city

Julie_perez:
20% is standard for H2A.

	Variable	[Units]	(y-axis,x-axis)	Data	Source Used
VarData	IClass			[3,5,1,1]	
VarData	OClass			[4,6,1]	
VarData	CYStart	[Year]		2025	
VarData	CYStop	[Year]		2050	
Axis	CY			[2025-2050]	
VarData	IRR	[%]		10%	3
VarData	DepreciationLength	[Years]		15	3
VarData	AnalysisPeriod	[Years]		20	
VarData	Life	[Years]		20	3
Axis	PY	PY		[1-20]	
VarData	DesignCapacity	[kgH2/day]		1,500	5
VarData	DesignCapacity	[kgH2/year]		547,500	
VarData	CapacityFactor	[% of DesignCapacity]		70%	3
VarData	AverageCapacity	[kgH2/day]		1050	
VarData	Location			3	
	DepreciableCapital (Direct)		(Component)		
	[\$] (ea.)		Overhead, Pipeline TOTAL	\$0.00	
	[\$m]		Unit Cost, Pipeline TOTAL	\$1,000,000.00	5
	DepreciableCapital (Indirect)		(Component)		
VarLinear	DepreciableCapital	[\$] (ea.)		(PY,CY)	2025 2050
Data			1	\$0.00 \$0.00	
End			20	\$0.00 \$0.00	
VarLinear	DepreciableCapitalPer	[\$] (/mile)		(PY,CY)	2025 2050
Data			1	\$1,000,000.00 \$1,000,000.00	
End			20	\$1,000,000.00 \$1,000,000.00	
VarData	LandRequired	[acres]		0	
	FixedOM		(Component)		
	(hours/year)		Labor Req'd	8,230	3
	[\$/hour]		Labor Costs	\$15.05	3
	[\$/year]		Labor Costs	\$123,861.50	
	[% of Labor]		Overhead and G&A	20%	5
	[% of DepreciableCapital]		Property Tax & Insurance	2.5%	5
	(\$/year)		Rent	\$0.00	
	[% of Installed Costs]		Lic., Permits and Fees	1.0%	3
	[% of Installed Costs]		Mart for Maint. & Repairs	0.5%	3
	(\$/year)		Other Fees	\$0.00	
	(\$/year)		Other Fixed O&M Costs	\$0.00	
VarLinear	FixedOM	[\$/year] (ea.)		(PY,CY)	2025 2050
Data			1	\$0.00 \$0.00	
End			20	\$0.00 \$0.00	
VarLinear	FixedOMPerMile	[\$/year] (/mile)		(PY,CY)	2025 2050
Data			1	\$40,000.00 \$40,000.00	
End			20	\$40,000.00 \$40,000.00	
VarLinear	FixedOMOverall	[\$/year] (overall)		(CY)	2025 2050
Data				\$148,633.90 \$148,633.90	
VarLinear	OtherFixed	[\$/year] (ea.)		(PY,CY)	2025 2050
Data			1	\$0.00 \$0.00	
End			20	\$0.00 \$0.00	
VarLinear	FeedstockEfficiency		(Feedstock,CY)	2025 2050	
Data					
	(GJH2/GJFeedstock)		Commercial Natural Gas	0.0000	
	(GJH2/GJFeedstock)		Industrial Natural Gas	0.0000	
	(GJH2/GJFeedstock)		Electric Utility Natural Gas	0.0000	
	(GJH2/GJ)		Commercial Electricity	0.0000	
	(GJH2/GJ)		Industrial Electricity	0.0000	
	(GJH2/GJFeedstock)		Utility Steam Coal (Central)	0.0000	
	(GJH2/GJFeedstock)		Diesel Fuel	0.0000	
	(GJH2/GJFeedstock)		Biomass	0.0000	
	(GJH2/GJFeedstock)		Ethanol	0.0000	
	(GJH2/GJFeedstock)		Methanol	0.0000	
	(GJH2/GJFeedstock)		Gasoline	0.0000	
	(GJH2/GJFeedstock)		Steam	0.0000	
	(GJH2-L)		Cooling Water	0.0000	
	(GJH2-L)		Demineralized Water	0.0000	
	(GJH2-L)		Process Water	0.0000	
	(GJH2/Barrel)		Bio-oil	0.0000	
	(GJH2/GJFeedstock)		Utility Steam Coal (Regional)	0.0000	
	(GJH2/GJFeedstock)		MSW (1)	0.0000	
	(GJH2/GJFeedstock)		MSW (2)	0.0000	
End					
VarLinear	OtherVariableOM	[\$/kgH2]		(PY,CY)	2025 2050
Data			1	\$0.0000 \$0.0000	
End			20	\$0.0000 \$0.0000	
VarLinear	ByproductEfficiency		(Byproduct,CY)	2025 2050	
Data					
	(GJH2/GJ)		Byproduct Electricity	0.0000	
End					
	(GJH2/GJFeedstock)		Steam	0.0000	
VarLinear	Emissions	[kg/kgH2]	(Species,CY)	2025 2050	
Data					
			Carbon	0	0
			GHG Equivalents	0	0
			NOx	0	0
			SOx	0	0
			Particulates (PM10)	0	0
			Mercury	0	0
End					
VarLinear	ReplacementCosts	[\$] (ea.)		(PY,CY)	2025 2050
Data			1	\$0.00 \$0.00	
End			20	\$0.00 \$0.00	

Julie_perez:
Through Sig Gronich
formerly of DOE.

julie_perez:
Through Sig Gronich
formerly of DOE.

0	Variable	[Units]	(y-axis,x-axis)	Data	Source Used
Var/Data	IClass			{4,1,1,1}	
Var/Data	OClass			{5,1,1}	
Var/Data	CYStart	[Year]		2005	
Var/Data	CYStop	[Year]		2050	
Axis	CY	CY		{2005-2050}	
Var/Data	IRR	[%]		10%	3
Var/Data	DepreciationLength	[Years]		7	2
Var/Data	AnalysisPeriod	[Years]		20	
Var/Data	Life	[Years]		20	2
Axis	PY	PY		{1-20}	
Var/Data	DesignCapacity	[kgH2/day]		100	3
Var/Data	DesignCapacity	[kgH2/day]		36,500	
Var/Data	CapacityFactor	[% of DesignCapacity]		70%	3
Var/Data	AverageCapacity	[kgH2/day]		70	
Var/Data	Location			3	
Engineering Assumptions					
Truck		(Component,CY)		2005 2020	
	(deg. C)	Temperature		25 25	
	(atm)	Maximum Pressure		180 180	
Dispensers		(Component,CY)		2005 2020	
	(atm)	Maximum Pressure		425 817	2005: 3 2020: 1 3
		Quantity		1 1	
Dispenser Compressors		(Component,CY)		2005 2020	
		Compressibility Factor		#NAME? #NAME?	
		(built) Quantity		3 1	2005: 3 2020: 1
		(needed) Quantity		2 1	2005: 3 2020: 1
	[#]	Design Flowrate		50 100	
	[#]	Average Flowrate		35 70	
		Stages		4 4	3
	[%]	Efficiency		65% 80%	2005: 3 2020: 1
Storage, GH2	[kW] (ea.)	Average Power Req'd		#NAME? #NAME?	
		(Component,CY)		2005 2020	
	[kgH2]	Usable Capacity		38 38	3
Costs					
DepreciableCapital (Direct)		(Component,CY)		2005 2020	
	(\$/m)	Unit Cost, Dispensers		\$26,880.00 \$26,880.00	3
	(\$)	Dispensers		\$26,880.00 \$26,880.00	
	(\$/kgH2/yr) (ea.)	Unit Cost, Dis. Compr.		\$6,300.00 \$6,300.00	2005: 3 2020: 8
	(\$)	Dis. Compr.		\$39,375.00 \$26,250.00	
	(\$/kgH2 Usable Capacity)	Unit Cost, Storage		\$818.00 \$594.00	2005: 3 2020: 8
	(\$)	Storage		\$31,084.00 \$22,458.00	
	(\$)	Ctrl. & Safety Equip.		\$22,320.00 \$22,320.00	
	(\$)	GT Trailer		\$450,000.00 \$450,000.00	5
DepreciableCapital (Indirect)		(Component)		2005 2020	
	[% of Installed Costs]	Site Preparation		6.5%	3
	[% of Installed Costs]	Engineering & Design		3%	3
	(\$)	Process Contingency		\$0.00	2
	[% of Installed Costs]	Project Contingency		5%	55
	(\$)	Other Depreciable Capital		\$0.00	3
	(\$)	One-Time Licensing Fees		\$0.00	3
	[% of Installed Costs]	Up-Front Permitting Costs		3%	3
Var/Nearest	DepreciableCapital	(\$)		2005 2035 2050	
Data				\$669,349.33 \$643,791.90 \$643,791.90	
Var/Data	LandRequired	[acres]		0	
FixedOM		(Component,CY)		2005 2035	
	(hours/year)	Labor Req'd, Maint.		72 72	3
	(\$/hour)	Labor Costs, Maint.		\$24.20 \$24.20	3
	(\$/year)	Labor Costs, Maint.		\$1,742.40 \$1,742.40	
	(hours/year)	Labor Req'd, Other		411 411	
	(\$/hour)	Labor Costs, Other		\$15.00 \$15.00	3
	(\$/year)	Labor Costs, Other		\$6,159.38 \$6,159.38	
	(\$/year)	Labor Costs		\$7,901.78 \$7,901.78	
	[% of Labor]	Overhead and G&A		20% 20%	3
	[% of DepreciableCapital]	Property Tax & Insurance		2% 2%	3
	(\$/year)	Rent		\$32,148.00 \$32,148.00	52
	[% of DepreciableCapital]	Lic., Permits and Fees		0.1% 0.1%	3
	[% of DepreciableCapital]	Matt for Maint. & Repairs		1.8% 1.5%	2005: 3 2020: 5
	(\$/year)	Other Fees		\$0.00 \$0.00	3
FixedOM	(\$/year)	Other Fixed O&M Costs		\$0.00 \$0.00	3
Var/Nearest	FixedOM	(\$)		2005 2035 2050	
Data				\$67,734.75 \$64,806.64 \$64,806.64	
End				1	
Var/Nearest	OtherFixed	(\$/year)		2005 2050	
Data				\$0.00 \$0.00	
End				1	
Var/Nearest	FeedstockEfficiency			2005 2035 2050	
Data				\$0.00 \$0.00 \$0.00	
	[GJH2/GJFeedstock]	Commercial Natural Gas		0.0000 0.0000 0.0000	
	[GJH2/GJFeedstock]	Industrial Natural Gas		0.0000 0.0000 0.0000	
	[GJH2/GJFeedstock]	Electric Utility Natural Gas		0.0000 0.0000 0.0000	
	[GJH2/GJ]	Commercial Electricity		#NAME? #NAME? #NAME?	
	[GJH2/GJ]	Industrial Electricity		0.0000 0.0000 0.0000	
	[GJH2/GJFeedstock]	Utility Steam Coal (Central)		0.0000 0.0000 0.0000	
	[GJH2/GJFeedstock]	Diesel Fuel		0.0000 0.0000 0.0000	
	[GJH2/GJFeedstock]	Biomass		0.0000 0.0000 0.0000	
	[GJH2/GJFeedstock]	Ethanol		0.0000 0.0000 0.0000	
	[GJH2/GJFeedstock]	Methanol		0.0000 0.0000 0.0000	
	[GJH2/GJFeedstock]	Gasoline		0.0000 0.0000 0.0000	
	[GJH2/GJFeedstock]	Steam		0.0000 0.0000 0.0000	
	[GJH2/L]	Cooling Water		0.0000 0.0000 0.0000	
	[GJH2/L]	Demineralized Water		0.0000 0.0000 0.0000	
	[GJH2/L]	Process Water		0.0000 0.0000 0.0000	
	[GJH2/Barrel]	Bio-oil		0.0000 0.0000 0.0000	
	[GJH2/GJFeedstock]	lty Steam Coal (Regional)		0.0000 0.0000 0.0000	
	[GJH2/GJFeedstock]	MSW (1)		0.0000 0.0000 0.0000	
	[GJH2/GJFeedstock]	MSW (2)		0.0000 0.0000 0.0000	
				2005 2035 2050	
				\$0.0000 \$0.0000 \$0.0000	
Var/Nearest	ByproductEfficiency			2005 2050	
Data				0.0000 0.0000	
End				1	
Var/Nearest	Emissions			2005 2050	
Data				0 0	
		Carbon		0 0	
		GHG Equivalents		0 0	
		NOx		0 0	
		SOx		0 0	
		Particulates (PM10)		0 0	
		Mercury		0 0	
End				1	
Var/Nearest	ReplacementCosts	(\$)		2005 2035 2050	
Data				\$0.00 \$0.00 \$0.00	
				9 \$0.00 \$0.00 \$0.00	
				10 \$66,255.00 \$53,130.00 \$53,130.00	3
				11 \$0.00 \$0.00 \$0.00	
				20 \$0.00 \$0.00 \$0.00	
				20 \$0.00 \$0.00 \$0.00	
				20 \$0.00 \$0.00 \$0.00	

Julie_perez:
Each Dispensing Station has 2 trailers to: a) cut down on # of deliveries req'd in a day, and b) allow for a more flexible delivery schedule rather than a "just in time" approach.

DOE research goal (2017) + 3 years development time=2020
This is supposed to be a technology breakthrough, so the appropriate command is VarNearest_2020+2020-2005=2035. With 2035 as a data point, VarNearest will use the 2005 value for 2019, use the 2035 value for 2020

0	Variable	[Units]	(y-axis,x-axis)	Data	Source Used
VarData	IClass			{4,2,1,1}	
VarData	OClass			{5,1,1}	
VarData	CYStart	[Year]		2005	
VarData	CYStop	[Year]		2050	
Axis	CY	CY		{2005-2050}	
VarData	IRR	[%]		10%	3
VarData	DepreciationLength	[Years]		7	2
VarData	AnalysisPeriod	[Years]		20	
VarData	Life	[Years]		20	2
Axis	PY	PY		{1-20}	
VarData	DesignCapacity	[kgH2/day]		1,500	3
VarData	DesignCapacity	[kgH2/day]		547,500	
VarData	CapacityFactor	[% of DesignCapacity]		70%	3
VarData	AverageCapacity	[kgH2/day]		1050	
VarData	Location			3	
Engineering Assumptions					
Truck		(Component,CY)		2005 2020	
	[deg. C]	Temperature		25 25	
	[atm]	Maximum Pressure		476 476	
Dispensers		(Component,CY)		2005 2020	
	[atm]	Maximum Pressure		425 817	2005: 3 2020: 1 3
		Quantity		3 3	
Dispenser Compressors		(Component,CY)		2005 2020	
		Compressibility Factor		#NAME? #NAME?	
	[#]	(built) Quantity		3 1	2005: 3 2020: 1 2005: 3 2020: 1
	[#]	(needed) Quantity		2 1	
	[kgH2/day] (ea.)	Design Flowrate		750 1,500	
	[kgH2/day] (ea.)	Average Flowrate		525 1,050	
	[#]	Stages		4 4	3 2005: 3 2020: 1
	[%]	Efficiency		65% 80%	
	[kW] (ea.)	Average Power Req'd		#NAME? #NAME?	
Storage, GH2		(Component,CY)		2005 2020	
	[kgH2]	Usable Capacity		358 358	3
Costs					
DepreciableCapital (Direct)		(Component,CY)		2005 2020	
	[\$/m]	Unit Cost, Dispensers		\$26,880.00 \$26,880.00	3
	[\$]	Dispensers		\$80,640.00 \$80,640.00	
	[\$/kgH2/yr] (ea.)	Unit Cost, Dis. Compr.		\$4,580.00 \$3,000.00	2005: 3 2020: 1
	[\$]	Dis. Compr.		\$429,375.00 \$187,500.00	
	[\$/kgH2 Usable Capacity]	Unit Cost, Storage		\$818.00 \$355.00	2005: 3 2020: 4
	[\$]	Storage		\$292,844.00 \$122,050.00	
	[\$]	Ctrl. & Safety Equip.		\$22,320.00 \$22,320.00	
	[\$]	HPGT Trailer		\$700,000.00 \$700,000.00	3
DepreciableCapital (Indirect)		(Component)		2005 2020	
	[% of Installed Costs]	Site Preparation		6.5% 3%	3
	[% of Installed Costs]	Engineering & Design		3% 3%	3
	[\$]	Process Contingency		\$0.00 \$0.00	2
	[% of Installed Costs]	Project Contingency		5% 5%	55
	[\$]	Other Depreciable Capital		\$0.00 \$0.00	3
	[\$]	One-Time Licensing Fees		\$0.00 \$0.00	3
	[% of Installed Costs]	Up-Front Permitting Costs		3% 3%	3
VarNearest	DepreciableCapital	[\$]	(CY)	2005 2035 2050	
Data				\$1,792,085.33 \$1,313,121.25 \$1,313,121.25	
VarData	LandRequired	[acres]		0	
FixedOM		(Component,CY)		2005 2020	
	[hours/year]	Labor Req'd, Maint.		72 72	3
	[\$/hour]	Labor Costs, Maint.		\$24.20 \$24.20	3
	[\$/year]	Labor Costs, Maint.		\$1,742.40 \$1,742.40	
	[hours/year]	Labor Req'd, Other		1,232 1,232	
	[\$/hour]	Labor Costs, Other		\$15.00 \$15.00	3
	[\$/year]	Labor Costs, Other		\$18,478.13 \$18,478.13	
	[\$/year]	Labor Costs		\$20,220.53 \$20,220.53	
	[% of Labor]	Overhead and G&A		20% 20%	3
	[% of DepreciableCapital]	Property Tax & Insurance		2% 2%	3
	[\$/year]	Rent		\$56,850.00 \$56,850.00	52
	[% of DepreciableCapital]	Lic., Permits and Fees		0.1% 0.1%	3
	[% of DepreciableCapital]	Matt for Maint. & Repairs		1.8% 1.5%	2005: 3 2020: 5
	[\$/year]	Other Fees		\$0.00 \$0.00	3
VarNearest	FixedOM	[\$]	(PY,CY)	2005 2050	
Data				\$151,005.96 \$128,387.00 \$128,387.00	
VarNearest	OtherFixed	[\$/year]	(PY,CY)	2005 2050	
Data				\$0.00 \$0.00	
VarNearest	FeedstockEfficiency		(Feedstock,CY)	2005 2035 2050	
Data				0.0000 0.0000 0.0000	
	[GJH2/GJFeedstock]	Commercial Natural Gas		0.0000 0.0000 0.0000	
	[GJH2/GJFeedstock]	Industrial Natural Gas		0.0000 0.0000 0.0000	
	[GJH2/GJFeedstock]	Electric Utility Natural Gas		0.0000 0.0000 0.0000	
	[GJH2/GJ]	Commercial Electricity		#NAME? #NAME? #NAME?	
	[GJH2/GJ]	Industrial Electricity		0.0000 0.0000 0.0000	
	[GJH2/GJFeedstock]	Utility Steam Coal (Central)		0.0000 0.0000 0.0000	
	[GJH2/GJFeedstock]	Diesel Fuel		0.0000 0.0000 0.0000	
	[GJH2/GJFeedstock]	Biomass		0.0000 0.0000 0.0000	
	[GJH2/GJFeedstock]	Ethanol		0.0000 0.0000 0.0000	
	[GJH2/GJFeedstock]	Methanol		0.0000 0.0000 0.0000	
	[GJH2/GJFeedstock]	Gasoline		0.0000 0.0000 0.0000	
	[GJH2/GJFeedstock]	Steam		0.0000 0.0000 0.0000	
	[GJH2/L]	Cooling Water		0.0000 0.0000 0.0000	
	[GJH2/L]	Demineralized Water		0.0000 0.0000 0.0000	
	[GJH2/L]	Process Water		0.0000 0.0000 0.0000	
	[GJH2/Barrel]	Bio-oil		0.0000 0.0000 0.0000	
	[GJH2/GJFeedstock]	lity Steam Coal (Regional)		0.0000 0.0000 0.0000	
	[GJH2/GJFeedstock]	MSW (1)		0.0000 0.0000 0.0000	
	[GJH2/GJFeedstock]	MSW (2)		0.0000 0.0000 0.0000	
				2005 2050	
VarNearest	OtherVariableOM	[\$/kgH2]	(PY,CY)	2005 2050	
Data				\$0.0000 \$0.0000	
VarNearest	ByproductEfficiency		(Byproduct,CY)	2005 2050	
Data				0.0000 0.0000	
VarNearest	Emissions	[kg/kgH2]	(Species,CY)	2005 2050	
Data				0 0	
		Carbon		0 0	
		GHG Equivalents		0 0	
		NOX		0 0	
		SOX		0 0	
		Particulates (PM10)		0 0	
		Mercury		0 0	
End					
VarNearest	ReplacementCosts	[\$]	(PY,CY)	2005 2035 2050	
Data				\$0.00 \$0.00 \$0.00	
				\$0.00 \$0.00 \$0.00	
				\$510,015.00 \$268,140.00 \$268,140.00	3
				\$0.00 \$0.00 \$0.00	
End				\$0.00 \$0.00 \$0.00	

Julie_perrez:
Each Dispensing Station has 2 trailers to: a) cut down on # of deliveries req'd in a day, and b) allow for a more flexible delivery schedule rather than a 'just in time' approach.

DOE research goal (2017) = 3 years development time - 2020

This is supposed to be a technology breakthrough, so the appropriate command is VarNearest: 2020-2020-2020-2035. With 2035 as a data point, VarNearest will use the 2005 value for 2019 and the 2035 value for 2020.

Life of Dispensers, Dispenser compressors is 10 years

0	Variable	[Units]	(y-axis,x-axis)	Data	Source Used
VarData	IClass			{4,3,1,1}	
VarData	OClass			{5,1,1}	
VarData	CYStart	[Year]		2020	
VarData	CYStop	[Year]		2050	
Axis	CY	CY		{2020-2050}	
VarData	IRR	[%]		10%	3
VarData	DepreciationLength	[Years]		7	2
VarData	AnalysisPeriod	[Years]		20	
VarData	Life	[Years]		20	2
Axis	PY	PY		{1-20}	
VarData	DesignCapacity	[kgH2/day]		1,500	3
VarData	DesignCapacity	[kgH2/day]		547,500	
VarData	CapacityFactor	[% of DesignCapacity]		70%	3
VarData	AverageCapacity	[kgH2/day]		1050	
VarData	Location			3	
Engineering Assumptions					
Truck					
	(deg. C)	Temperature		25	
	(atm)	Maximum Pressure		136	
	(atm)	Minimum Pressure		15	
Dispensers					
	(atm)	Maximum Pressure		817	1
		Quantity		3	3
Dispenser Compressors					
		Compressibility Factor		#NAME?	
	[#]	(built) Quantity		1	1
	[#]	(needed) Quantity		1	1
	[kgH2/day] (ea.)	Design Flowrate		1,500	
	[kgH2/day] (ea.)	Average Flowrate		1,050	
	[#]	Stages		4	3
	[%]	Efficiency		80%	1
	[kW] (ea.)	Average Power Req'd		#NAME?	
Storage, GH2					
	[kgH2]	Usable Capacity		358	3
Costs					
DepreciableCapital (Direct)					
	(\$m)	Unit Cost, Dispensers		\$26,880.00	3
	(\$)	Dispensers		\$80,640.00	
	[\$/(kgH2/yr)] (ea.)	Unit Cost, Dis. Compr.		\$3,000.00	1
	(\$)	Dis. Compr.		\$187,500.00	
	[\$/kgH2 Usable Capacity]	Unit Cost, Storage		\$355.00	4
	(\$)	Storage		\$127,090.00	
	(\$)	Ctrl. & Safety Equip.		\$22,320.00	3
	(\$)	CryoGT Trailer		\$745,000.00	11
	(\$)	Installed Costs		\$1,162,550.00	
DepreciableCapital (Indirect)					
	[% of Installed Costs]	Site Preparation		6.5%	3
	[% of Installed Costs]	Engineering & Design		3%	3
	(\$)	Process Contingency		\$0.00	2
	[% of Installed Costs]	Project Contingency		5%	55
	(\$)	Other Depreciable Capital		\$0.00	3
	(\$)	One-Time Licensing Fees		\$0.00	3
	[% of Installed Costs]	Up-Front Permitting Costs		3%	3
VarNearest	DepreciableCapital	(\$)		2020	
Data				2050	
VarData	LandRequired	(acres)		\$1,365,996.25	
				\$1,365,996.25	
FixedOM					
		(Component)			
	(hours/year)	Labor Req'd, Maint.		72	3
	(\$/hour)	Labor Costs, Maint.		\$24.20	3
	(\$/year)	Labor Costs, Maint.		\$1,742.40	
	(hours/year)	Labor Req'd, Other		1,232	
	(\$/hour)	Labor Costs, Other		\$15.00	3
	(\$/year)	Labor Costs, Other		\$18,478.13	
	(\$/year)	Labor Costs		\$20,220.53	
	[% of Labor]	Overhead and G&A		20%	3
	[% of DepreciableCapital]	Property Tax & Insurance		2%	3
	(\$/year)	Rent		\$46,950.00	52
	[% of DepreciableCapital]	Lic., Permits and Fees		0.1%	3
	[% of DepreciableCapital]	Mort for Maint. & Repairs		1.5%	5
	(\$/year)	Other Fees		\$0.00	3
	(\$/year)	Other Fixed O&M Costs		\$0.00	3
VarNearest	FixedOM	(\$)		2020	
Data				2050	
End				1	
VarNearest	OtherFixed	(\$/year)		2020	
Data				2050	
End				1	
VarNearest	FeedstockEfficiency			2020	
Data				2050	
	(GJH2/GJFeedstock)	Commercial Natural Gas		0.0000	0.0000
	(GJH2/GJFeedstock)	Industrial Natural Gas		0.0000	0.0000
	(GJH2/GJFeedstock)	Electric Utility Natural Gas		0.0000	0.0000
	(GJH2/GJ)	Commercial Electricity		#NAME?	#NAME?
	(GJH2/GJ)	Industrial Electricity		0.0000	0.0000
	(GJH2/GJFeedstock)	Utility Steam Coal (Central)		0.0000	0.0000
	(GJH2/GJFeedstock)	Diesel Fuel		0.0000	0.0000
	(GJH2/GJFeedstock)	Biomass		0.0000	0.0000
	(GJH2/GJFeedstock)	Ethanol		0.0000	0.0000
	(GJH2/GJFeedstock)	Methanol		0.0000	0.0000
	(GJH2/GJFeedstock)	Gasoline		0.0000	0.0000
	(GJH2/GJFeedstock)	Steam		0.0000	0.0000
	(GJH2/L)	Cooling Water		0.0000	0.0000
	(GJH2/L)	Deminerlized Water		0.0000	0.0000
	(GJH2/L)	Process Water		0.0000	0.0000
	(GJH2/Barrrel)	Bio-oil		0.0000	0.0000
	(GJH2/GJFeedstock)	lity Steam Coal (Regional)		0.0000	0.0000
	(GJH2/GJFeedstock)	MSW (1)		0.0000	0.0000
	(GJH2/GJFeedstock)	MSW (2)		0.0000	0.0000
VarNearest	OtherVariableOM	(\$/kgH2)		2020	
Data				2050	
End				1	
VarNearest	ByproductEfficiency			2020	
Data				2050	
End				1	
VarNearest	Emissions			2020	
Data				2050	
	(Specres.CY)	Carbon		0	0
		GHG Equivalents		0	0
		NOx		0	0
		SOx		0	0
		Particulates (PM10)		0	0
		Mercury		0	0
End				2020	
VarNearest	ReplacementCosts	(\$)		2020	
Data				2050	
				1	
				9	
				10	
				11	
				20	

julie_perrez:
Each Dispensing Station has 1 trailer
based on a size of 2100 kg. Accepts
some waste due to timing of deliveries.

Life of Dispensers, Dispenser compressors is 10 years.

	Variable	[Units]	(y-axis,x-axis)	Data	Source Used	
Var/Data	IClass			[4,4,1,1]		
Var/Data	OClass			[5,1,1]		
Var/Data	CYStart	[Year]		2005		
Var/Data	CYStop	[Year]		2050		
Axis	CY			[2005-2050]		
Var/Data	IRR	[%]		10%	3	
Var/Data	DepreciationLength	[Years]		7	2	
Var/Data	AnalysisPeriod	[Years]		20		
Var/Data	Life	[Years]		20	2	
Axis	PY			[1-20]		
Var/Data	DesignCapacity	[kgH2/day]		100	3	
Var/Data	DesignCapacity	[kgH2/year]		36,500		
Var/Data	CapacityFactor	[% of DesignCapacity]		70%	3	
Var/Data	AverageCapacity	[kgH2/day]		70		
Var/Data	Location			3		
Engineering Assumptions						
Dispensers		(Component)				
	Quantity		1		3	
Storage, GH2		(Component)				
	Usable Capacity		38		3	
Storage, LH2		(Component)				
	Desired Capacity		1496		3	
Pumps		(Component)				
	Quantity		2		3	
	Average Power Req'd		0.33		7	
Costs						
DepreciableCapital (Direct)		(Component,CY)	2005	2020		
	Unit Cost, Dispensers		\$26,880.00	\$26,880.00	3	
	Dispensers		\$26,880.00	\$26,880.00		
	Unit Cost, GH2 Storage		\$818.00	\$591.00	2005: 3	
	GH2 Storage		\$31,084.00	\$22,458.00	2020: 9	
	Unit Cost, LH2 Storage		\$70.00	\$70.00	3	
	LH2 Storage		\$104,720.00	\$104,720.00		
	Unit Cost, Pumps		\$22,607.00	\$22,607.00	3	
	Pumps		\$45,214.00	\$45,214.00		
	Evaporator		\$7,920.00	\$7,920.00	3	
	Ctrl. & Safety Equip.		\$22,320.00	\$22,320.00	3	
	Installed Costs		\$238,138.00	\$229,512.00		
DepreciableCapital (Indirect)		(Component)				
	Site Preparation		6.5%		3	
	Engineering & Design		3%		3	
	Process Contingency		\$0.00		2	
	Project Contingency		5%		55	
	Other Depreciable Capital		\$0.00		3	
	One-Time Licensing Fees		\$0.00		3	
	Up-Front Permitting Costs		3%		3	
Var/Nearest	DepreciableCapital	[\$]	(CY)	2005	2035	2050
Data				\$279,812.15	\$249,676.50	\$299,676.60
Var/Data	LandRequired	[acres]		0		
FixedOM		(Component,CY)	2005			
	Labor Req'd, Maint.		72	72		3
	Labor Costs, Maint.		\$24.20	\$24.20		3
	Labor Costs, Maint.		\$1,742.40	\$1,742.40		
	Labor Req'd, Other		411	411		
	Labor Costs, Other		\$15.00	\$15.00		3
	Labor Costs, Other		\$6,159.38	\$6,159.38		
	Labor Costs		\$7,901.78	\$7,901.78		
	Overhead and G&A		20%	20%		3
	Property Tax & Insurance		2%	2%		3
	Rent		\$34,134.00	\$34,134.00		52
	Lic., Permits and Fees		0.1%	0.1%		3
	Mart'l for Maint. & Repairs		1.8%	1.5%		2020: 5
	Other Fees		\$0.00	\$0.00		3
	Other Fixed O&M Costs		\$0.00	\$0.00		3
Var/Nearest	FixedOM	[\$]	(PY,CY)	2005	2035	2050
Data				\$54,528.80	\$53,324.49	\$53,324.49
End				\$54,528.80	\$53,324.49	\$53,324.49
Var/Nearest	OtherFixed	[\$/year]	(PY,CY)	2005	2050	
Data				\$0.00	\$0.00	\$0.00
End				\$0.00	\$0.00	\$0.00
Var/Nearest	FeedstockEfficiency		(Feedstock,CY)	2005	2050	
Data				0.0000	0.0000	
	Commercial Natural Gas			0.0000	0.0000	
	Industrial Natural Gas			0.0000	0.0000	
	Electric Utility Natural Gas			0.0000	0.0000	
	Commercial Electricity			102.2493	102.2493	
	Industrial Electricity			0.0000	0.0000	
	Utility Steam Coal (Central)			0.0000	0.0000	
	Diesel Fuel			0.0000	0.0000	
	Biomass			0.0000	0.0000	
	Ethanol			0.0000	0.0000	
	Methanol			0.0000	0.0000	
	Gasoline			0.0000	0.0000	
	Steam			0.0000	0.0000	
	Cooling Water			0.0000	0.0000	
	Demineralized Water			0.0000	0.0000	
	Process Water			0.0000	0.0000	
	Bio-oil			0.0000	0.0000	
	Utility Steam Coal (Regional)			0.0000	0.0000	
	MSW (1)			0.0000	0.0000	
	MSW (2)			0.0000	0.0000	
Var/Nearest	OtherVariableOM	[\$/kgH2]	(PY,CY)	2005	2050	
Data				\$0.0000	\$0.0000	\$0.0000
End				\$0.0000	\$0.0000	\$0.0000
Var/Nearest	ByproductEfficiency		(Byproduct,CY)	2005	2050	
Data				0.0000	0.0000	
End				0.0000	0.0000	
Var/Nearest	Emissions	[kg/kgH2]	(Species,CY)	2005	2050	
Data				0	0	
	Carbon			0	0	
	GHG Equivalents			0	0	
	NOX			0	0	
	SOX			0	0	
	Particulates (PM10)			0	0	
	Mercury			0	0	
Var/Nearest	ReplacementCosts	[\$]	(PY,CY)	2005	2035	2050
Data				\$0.00	\$0.00	\$0.00
				\$0.00	\$0.00	\$0.00
				\$26,880.00	\$26,880.00	\$26,880.00
				\$0.00	\$0.00	\$0.00
End				\$0.00	\$0.00	\$0.00

DOE research goal (2017) = 3 years development time

Life of Dispensers is 10 years

0	Variable	[Units]	(y-axis,x-axis)	Data	Source Used
Var/Data	IClass		(Component)	[4,5,1,1]	
Var/Data	OClass		(Component)	[5,1,1]	
Var/Data	CYStart	[Year]		2005	
Var/Data	CYStop	[Year]		2050	
Axis	CY			[2005-2050]	
Var/Data	IRR	[%]		10%	3
Var/Data	DepreciationLength	[Years]		7	2
Var/Data	AnalysisPeriod	[Years]		20	
Var/Data	Life	[Years]		20	2
Axis	PY			[1-20]	
Var/Data	DesignCapacity	[kgH2/day]		1,500	3
Var/Data	DesignCapacity	[kgH2/year]		547,500	
Var/Data	CapacityFactor	[% of DesignCapacity]		70%	3
Var/Data	AverageCapacity	[kgH2/day]		1050	
Var/Data	Location			3	
Engineering Assumptions					
Dispensers					
		(Component)			
		Quantity		3	3
Storage, GH2					
		(Component)			
		Usable Capacity		358	3
Storage, LH2					
		(Component)			
		Desired Capacity		4488	3
Pumps					
		(Component)			
		Quantity		2	3
		Average Power Req'd		0.33	6
Costs					
DepreciableCapital (Direct)					
		(Component)			
		2005	2020		
		Unit Cost, Dispensers	\$26,880.00	\$26,880.00	3
		Dispensers	\$80,640.00	\$80,640.00	
		Unit Cost, GH2 Storage	\$818.00	\$355.00	2005: 3
		GH2 Storage	\$292,844.00	\$127,090.00	2020: 4
		Unit Cost, LH2 Storage	\$50.00	\$50.00	3
		LH2 Storage	\$224,400.00	\$224,400.00	
		Unit Cost, Pumps	\$29,638.00	\$29,638.00	3
		Pumps	\$59,276.00	\$59,276.00	
		Evaporator	\$12,988.00	\$12,988.00	3
		Ctrl. & Safety Equip.	\$22,320.00	\$22,320.00	3
		Installed Costs	\$692,468.00	\$526,714.00	
DepreciableCapital (Indirect)					
		(Component)			
		Site Preparation	6.5%		3
		Engineering & Design	3%		3
		Process Contingency	\$0.00		2
		Project Contingency	5%		55
		Other Depreciable Capital	\$0.00		3
		One-Time Licensing Fees	\$0.00		3
		Up-Front Permitting Costs	3%		3
Var/Nearest	DepreciableCapital	[\$]	(CY)	2005 2035 2050	
Data				\$813,643.95 \$618,886.35 \$618,888.95	
Var/Data	LandRequired	[acres]		0	
FixedOM					
		(Component,CY)			
		2005			
		Labor Req'd, Maint.	72	72	3
		Labor Costs, Maint.	\$24.20	\$24.20	3
		Labor Costs, Maint.	\$1,742.40	\$1,742.40	
		Labor Req'd, Other	1,232	1,232	
		Labor Costs, Other	\$15.00	\$15.00	3
		Labor Costs, Other	\$18,478.13	\$18,478.13	
		Labor Costs	\$20,220.53	\$20,220.53	
		Overhead and G&A	20%	20%	3
		Property Tax & Insurance	2%	2%	3
		Rent	\$65,394.00	\$65,394.00	52
		Lic., Permits and Fees	0.1%	0.1%	3
		Mart'l for Maint. & Repairs	1.8%	1.5%	2020: 5
		Other Fees	\$0.00	\$0.00	3
		Other Fixed O&M Costs	\$0.00	\$0.00	3
Var/Nearest	FixedOM	[\$]	(PY,CY)	2005 2035 2050	
Data				\$121,390.98 \$111,938.63 \$111,938.63	
End				\$121,390.98 \$111,938.63 \$111,938.63	
Var/Nearest	OtherFixed	[\$/year]	(PY,CY)	2005 2050	
Data				\$0.00 \$0.00	
End				\$0.00 \$0.00	
Var/Nearest	FeedstockEfficiency		(Feedstock,CY)	2005 2050	
Data				0.0000 0.0000	
		Commercial Natural Gas	0.0000	0.0000	
		Industrial Natural Gas	0.0000	0.0000	
		Electric Utility Natural Gas	0.0000	0.0000	
		Commercial Electricity	102.2493	102.2493	
		Industrial Electricity	0.0000	0.0000	
		Utility Steam Coal (Central)	0.0000	0.0000	
		Diesel Fuel	0.0000	0.0000	
		Biomass	0.0000	0.0000	
		Ethanol	0.0000	0.0000	
		Methanol	0.0000	0.0000	
		Gasoline	0.0000	0.0000	
		Steam	0.0000	0.0000	
		Cooling Water	0.0000	0.0000	
		Demineralized Water	0.0000	0.0000	
		Process Water	0.0000	0.0000	
		Bio-oil	0.0000	0.0000	
		Utility Steam Coal (Regional)	0.0000	0.0000	
		MSW (1)	0.0000	0.0000	
		MSW (2)	0.0000	0.0000	
End					
Var/Nearest	OtherVariableOM	[\$/kgH2]	(PY,CY)	2005 2050	
Data				\$0.0000 \$0.0000	
End				\$0.0000 \$0.0000	
Var/Nearest	ByproductEfficiency		(Byproduct,CY)	2005 2050	
Data				0.0000 0.0000	
End				0.0000 0.0000	
Var/Nearest	Emissions	[kg/kgH2]	(Species,CY)	2005 2050	
Data				0 0	
		Carbon	0	0	
		GHG Equivalents	0	0	
		NOX	0	0	
		SOX	0	0	
		Particulates (PM10)	0	0	
		Mercury	0	0	
End					
Var/Nearest	ReplacementCosts	[\$]	(PY,CY)	2005 2035 2050	
Data				\$0.00 \$0.00 \$0.00	
				\$0.00 \$0.00 \$0.00	
				\$80,640.00 \$80,640.00 \$80,640.00	3
				\$0.00 \$0.00 \$0.00	
End				\$0.00 \$0.00 \$0.00	

DOE research goal (2017) + 3 years development time

Life of Dispensers is 10 years

0	Variable	[Units]	(y-axis,x-axis)	Data	Source Used
Var/Data	IClass			[4,6,1,1]	
Var/Data	OClass			[5,1,1]	
Var/Data	CYStart	[Year]		2005	
Var/Data	CYStop	[Year]		2050	
Axis	CY	CY		[2005-2050]	
Var/Data	IRR	[%]		10%	3
Var/Data	DepreciationLength	[Years]		7	2
Var/Data	AnalysisPeriod	[Years]		20	
Var/Data	Life	[Years]		20	2
Axis	PY	PY		[1-20]	
Var/Data	DesignCapacity	[kgH2/day]		1,500	3
Var/Data	DesignCapacity	[kgH2/day]		547,500	
Var/Data	CapacityFactor	[% of DesignCapacity]		70%	3
Var/Data	AverageCapacity	[kgH2/day]		1050	
Var/Data	Location			3	
Engineering Assumptions					
	Pipeline	(Component,CY)		2005 2020	
		(deg. C)	Temperature	25 25	
		(atm)	Pressure	20 20	
	Dispensers	(Component,CY)		2005 2020	
		(atm)	Maximum Pressure	425 817	2005: 3
			Quantity	3 3	2020: 1
	Dispenser Compressors	(Component,CY)		2005 2020	
			Compressibility Factor	#NAME? #NAME?	3
			(built) Quantity	3 1	2005: 3
			(needed) Quantity	2 1	2020: 1
			Design Flowrate	750 1,500	2005: 3
			Average Flowrate	525 1,050	2020: 1
			Stages	4 4	
			Efficiency	65% 80%	3
			Average Power Req'd	#NAME? #NAME?	2005: 3
	Storage, GH2	(Component,CY)		2005 2020	2020: 1
			Usable Capacity	358 358	
Costs					
	DepreciableCapital (Direct)	(Component,CY)		2005 2020	
		Unit Cost, Dispensers		\$26,880.00 \$26,880.00	3
		Dispensers		\$80,640.00 \$80,640.00	
		Unit Cost, Dis. Compr.		\$4,580.00 \$3,000.00	2005: 3
		Dis. Compr.		\$429,375.00 \$187,500.00	2020: 1
		Unit Cost, Storage		\$918.00 \$355.00	2005: 3
		Storage		\$292,844.00 \$127,090.00	2020: 4
		Ctrl. & Safety Equip.		\$22,320.00 \$22,320.00	
		Installed Costs		\$825,179.00 \$417,550.00	3
	DepreciableCapital (Indirect)	(Component)			
		Site Preparation		6.5%	3
		Engineering & Design		3%	3
		Process Contingency		\$0.00	2
		Project Contingency		5%	55
		Other Depreciable Capital		\$0.00	3
		One-Time Licensing Fees		\$0.00	3
		Up-Front Permitting Costs		3%	3
Var/Nearest	DepreciableCapital	[\$]	(CY)	2005 2035 2050	
Data				\$969,585.33 \$490,621.25 \$490,621.25	
Var/Data	LandRequired	[acres]		0	
Var/Data	FixedOM	(Component,CY)		2005 2020	
		Labor Req'd, Maint.		72 72	3
		Labor Costs, Maint.		\$24.20 \$24.20	3
		Labor Costs, Maint.		\$1,742.40 \$1,742.40	
		Labor Req'd, Other		1,232 1,232	
		Labor Costs, Other		\$15.00 \$15.00	3
		Labor Costs, Other		\$18,478.13 \$18,478.13	
		Labor Costs		\$20,220.53 \$20,220.53	
		Overhead and G&A		20% 20%	3
		Property Tax & Insurance		2% 2%	3
		Rent		\$33,750.00 \$33,750.00	52
		Lic., Permits and Fees		0.1% 0.1%	3
		Maint for Maint. & Repairs		1.8% 1.5%	2005: 3
		Other Fees		\$0.00 \$0.00	2020: 5
		Other Fixed O&M Costs		\$0.00 \$0.00	3
Var/Nearest	FixedOM	[\$]	(PY,CY)	2005 2035 2050	
Data				1 \$95,628.46 \$75,677.00 \$75,677.00	
End				20 \$95,628.46 \$75,677.00 \$75,677.00	
Var/Nearest	OtherFixed	[\$/year]	(PY,CY)	2005 2020	
Data				1 \$0.00 \$0.00	
End				20 \$0.00 \$0.00	
Var/Nearest	FeedstockEfficiency	(Feedstock,CY)		2005 2035 2050	
Data		Commercial Natural Gas		0.0000 0.0000 0.0000	
		Industrial Natural Gas		0.0000 0.0000 0.0000	
		Electric Utility Natural Gas		0.0000 0.0000 0.0000	
		Commercial Electricity		#NAME? #NAME? #NAME?	
		Industrial Electricity		0.0000 0.0000 0.0000	
		Utility Steam Coal (Central)		0.0000 0.0000 0.0000	
		Diesel Fuel		0.0000 0.0000 0.0000	
		Biomass		0.0000 0.0000 0.0000	
		Ethanol		0.0000 0.0000 0.0000	
		Methanol		0.0000 0.0000 0.0000	
		Gasoline		0.0000 0.0000 0.0000	
		Steam		0.0000 0.0000 0.0000	
		Cooling Water		0.0000 0.0000 0.0000	
		Demineralized Water		0.0000 0.0000 0.0000	
		Process Water		0.0000 0.0000 0.0000	
		Bio-oil		0.0000 0.0000 0.0000	
		Utility Steam Coal (Regional)		0.0000 0.0000 0.0000	
		MSW (1)		0.0000 0.0000 0.0000	
		MSW (2)		0.0000 0.0000 0.0000	
End					
Var/Nearest	OtherVariableOM	[\$/kgH2]	(PY,CY)	2005 2050	
Data				1 \$0.0000 \$0.0000	
End				20 \$0.0000 \$0.0000	
Var/Nearest	ByproductEfficiency	(Byproduct,CY)		2005 2050	
Data		Byproduct Electricity		0.0000 0.0000	
End		Steam		0.0000 0.0000	
Var/Nearest	Emissions	(Species,CY)		2005 2050	
Data		Carbon		0 0	
		GHG Equivalents		0 0	
		NOx		0 0	
		SOx		0 0	
		Particulates (PM10)		0 0	
		Mercury		0 0	
End					
Var/Nearest	ReplacementCosts	[\$]	(PY,CY)	2005 2035 2050	
Data				1 \$0.00 \$0.00 \$0.00	
				9 \$0.00 \$0.00 \$0.00	
				10 \$510,015.00 \$268,140.00 \$268,140.00	3
				11 \$0.00 \$0.00 \$0.00	
End				20 \$0.00 \$0.00 \$0.00	

DOE research goal (2017) + 3 years development time ~2020
 This is supposed to be a technology breakthrough, so the appropriate command is Var/Nearest, 2020~2020-2005~2035. With 2035 as a data point, Var/Nearest will
 - use the 2005 value for 2019
 - use the 2035 value for 2020

Life of Dispensers, Dispenser compressors is 10 years

0	Variable	[Units]	(y-axis, x-axis)	Data	Source Used
Var/Data	IClass			[4,7,1,1]	
Var/Data	OClass			[5,1,1]	
Var/Data	CYStart	[Year]		2005	
Var/Data	CYStop	[Year]		2050	
Axis	CY			[2005-2050]	
Var/Data	IRR	[%]		10%	2
Var/Data	DepreciationLength	[Years]		7	2
Var/Data	AnalysisPeriod	[Years]		20	
Var/Data	Life	[Years]		20	2
Axis	PY			[1-20]	
Var/Data	DesignCapacity	[kgH2/day]		100	2
Var/Data	CapacityFactor	[% of DesignCapacity]		36.500	3
Var/Data	AverageCapacity	[kgH2/day]		70	
Var/Data	Location			3	
Engineering Assumptions					
Forecourt		(Component,CY)		2005 2020	
	(deg. C)	Temperature		25 25	
	(atm)	Pressure		20 20	
Dispensers		(Component,CY)		2005 2020	
	(atm)	Maximum Pressure		425 817	2005: 3
		Quantity		1 1	2020: 1
Dispenser Compressors		(Component,CY)		2005 2020	
		Compressibility Factor		1.1384 1.2542	2
	(#)	(built) Quantity		3 1	2005: 3
	(#)	(needed) Quantity		2 1	2020: 1
	[kgH2/day] (ea.)	Design Flowrate		50 100	2005: 3
	[kgH2/day] (ea.)	Average Flowrate		35 70	2020: 1
	(#)	Stages		4 4	
	[%]	Efficiency		65% 80%	2
	[kW] (ea.)	Average Power Req'd		3.0 6.7	2005: 3
Storage, GH2		(Component,CY)		2005 2020	
	[kgH2]	Design Capacity		79.54545455 79.54545455	2020: 1
Costs					
DepreciableCapital (Direct)		(Component,CY)		2005 2020	
	Unit Cost, Dispensers			\$26,880.00 \$26,880.00	2
	Dispensers			\$26,880.00 \$26,880.00	
	Unit Cost, Dis. Compr.			\$6,300.00 \$ 6,300.00	2005: 2
	Dis. Compr.			\$39,375.00 \$26,250.00	2020: 8
	Unit Cost, Storage			\$918.00 \$591.00	2005: 2
	Storage			\$65,068.18 \$47,011.36	2020: 8
	Ctrl. & Safety Equip.			\$22,320.00 \$22,320.00	
	Installed Costs			\$153,643.18 \$122,461.36	2
DepreciableCapital (Indirect)		(Component)			
	Site Preparation			6.5%	3
	Engineering & Design			3%	3
	Process Contingency			\$0.00	2
	Project Contingency			5%	55
	Other Depreciable Capital			\$0.00	2
	One-Time Licensing Fees			\$0.00	3
	Up-Front Permitting Costs			3%	3
Var/Nearest	DepreciableCapital	(\$)	(CY)	2005 2035 2050	
Data				\$180,530.74 \$143,892.10 \$143,892.10	
Var/Data	LandRequired	[acres]		0	
FixedOM		(Component,CY)		2005 2020	
	Labor Req'd, Maint.			72 72	3
	Labor Costs, Maint.			\$24.20 \$24.20	3
	Labor Costs, Maint.			\$1,742.40 \$1,742.40	
	Labor Req'd, Other			411 411	
	Labor Costs, Other			\$15.00 \$15.00	3
	Labor Costs, Other			\$6,159.38 \$6,159.38	
	Labor Costs			\$7,901.78 \$7,901.78	
	Overhead and G&A			20% 20%	2
	Property Tax & Insurance			1% 1%	2
	Rent			\$11,250.00 \$11,250.00	52
	Lic., Permits and Fees			0.1% 0.1%	3
	Mart for Maint. & Repairs			1.8% 1.5%	2005: 3
	Other Fees			\$0.00 \$0.00	3
	Other Fixed O&M Costs			\$0.00 \$0.00	2020: 5
Var/Nearest	FixedOM	(\$)	(PY,CY)	2005 2035 2050	
Data				\$25,967.52 \$24,473.32 \$24,473.32	
End				\$25,967.52 \$24,473.32 \$24,473.32	
Var/Nearest	OtherFixed	(\$/year)	(PY,CY)	2005 2020	
Data				\$0.00 \$0.00	
End				\$0.00 \$0.00	
Var/Nearest	FeedstockEfficiency		(Feedstock,CY)	2005 2035 2050	
Data				0.0000 0.0000 0.0000	
	[GJH2/GJFeedstock]	Commercial Natural Gas		0.0000 0.0000 0.0000	
	[GJH2/GJFeedstock]	Industrial Natural Gas		0.0000 0.0000 0.0000	
	[GJH2/GJFeedstock]	Electric Utility Natural Gas		0.0000 0.0000 0.0000	
	[GJH2/GJ]	Commercial Electricity		16.4788 14.7954 14.7954	
	[GJH2/GJ]	Industrial Electricity		0.0000 0.0000 0.0000	
	[GJH2/GJFeedstock]	Jillly Steam Coal (Central)		0.0000 0.0000 0.0000	
	[GJH2/GJFeedstock]	Diesel Fuel		0.0000 0.0000 0.0000	
	[GJH2/GJFeedstock]	Biomass		0.0000 0.0000 0.0000	
	[GJH2/GJFeedstock]	Ethanol		0.0000 0.0000 0.0000	
	[GJH2/GJFeedstock]	Methanol		0.0000 0.0000 0.0000	
	[GJH2/GJFeedstock]	Gasoline		0.0000 0.0000 0.0000	
	[GJH2/GJFeedstock]	Steam		0.0000 0.0000 0.0000	
	[GJH2/L]	Cooling Water		0.0000 0.0000 0.0000	
	[GJH2/L]	Demineralized Water		0.0000 0.0000 0.0000	
	[GJH2/L]	Process Water		0.0000 0.0000 0.0000	
	[GJH2/Barrel]	Bio-oil		0.0000 0.0000 0.0000	
	[GJH2/GJFeedstock]	lity Steam Coal (Regional)		0.0000 0.0000 0.0000	
	[GJH2/GJFeedstock]	MSW (1)		0.0000 0.0000 0.0000	
	[GJH2/GJFeedstock]	MSW (2)		0.0000 0.0000 0.0000	
End				0.0000 0.0000 0.0000	
Var/Nearest	OtherVariableOM	(\$/kgH2)	(PY,CY)	2005 2050	
Data				\$0.0000 \$0.0000	
End				\$0.0000 \$0.0000	
Var/Nearest	ByproductEfficiency		(Byproduct,CY)	2005 2050	
Data				0.0000 0.0000	
End				0.0000 0.0000	
Var/Nearest	Emissions	[kg/kgH2]	(Species,CY)	2005 2050	
Data				0 0	
	Carbon			0 0	
	GHG Equivalents			0 0	
	NOx			0 0	
	SOx			0 0	
	Particulates (PM10)			0 0	
	Mercury			0 0	
End				0 0	
Var/Nearest	ReplacementCosts	(\$)	(PY,CY)	2005 2035 2050	
Data				\$0.00 \$0.00 \$0.00	
				\$0.00 \$0.00 \$0.00	
				\$66,255.00 \$53,130.00 \$53,130.00	3
				\$0.00 \$0.00 \$0.00	
				\$0.00 \$0.00 \$0.00	
End				\$0.00 \$0.00 \$0.00	

Julie_perez:
Source 2 says Storage Design Capacity (kg) 80: Storage Usable Capacity (kg) 35.

DOE research goal (2017) + 3 years development time = 2020
This is supposed to be a technology breakthrough, so the appropriate command is Var/Nearest: 2020 + 2020-2005 = 2035.
With 2035 as a data point, Var/Nearest will
- use the 2005 value for 2019
- use the 2035 value for 2020

Life of Dispensers & Dispensing compressors is 10 years

0	Variable	[Units]	(y-axis,x-axis)	Data	Source Used
Var/Data	IClass			[4,8,1,1]	
Var/Data	OClass			[5,1,1]	
Var/Data	CYStart	[Year]		2005	
Var/Data	CYStop	[Year]		2050	
Axis	CY			[2005-2050]	
Var/Data	IRR	[%]		10%	2
Var/Data	DepreciationLength	[Years]		7	2
Var/Data	AnalysisPeriod	[Years]		20	
Var/Data	Life	[Years]		20	2
Axis	PY			[1-20]	
Var/Data	DesignCapacity	[kgH2/day]		1,500	2
Var/Data	DesignCapacity	[kgH2/year]		547,500	
Var/Data	CapacityFactor	[% of DesignCapacity]		70%	3
Var/Data	AverageCapacity	[kgH2/day]		1050	
Var/Data	Location			3	
Engineering Assumptions					
Forecourt			(Component,CY)	2005 2020	
	(deg. C)	Temperature		25 25	
	(atm)	Pressure		20 20	
Dispensers			(Component,CY)	2005 2020	
	(atm)	Maximum Pressure		425 817	2005: 3
		Quantity		3 3	2020: 1
Dispenser Compressors			(Component,CY)	2005 2020	
		Compressibility Factor		1.1384 1.2542	2
	(#)	(built) Quantity		3 1	2005: 3
	(#)	(needed) Quantity		2 1	2005: 3
	[kgH2/day] (ea.)	Design Flowrate		750 1,500	2020: 1
	[kgH2/day] (ea.)	Average Flowrate		525 1,050	
	(#)	Stages		4 4	2
	[%]	Efficiency		65% 80%	2005: 3
	[kW] (ea.)	Average Power Req'd		44.8 99.8	2020: 1
Storage, GH2			(Component,CY)	2005 2020	
	[kgH2]	Design Capacity		1193.181818 1193.181818	2
Costs					
DepreciableCapital (Direct)			(Component,CY)	2005 2020	
	Unit Cost, Dispensers			\$26,880.00 \$26,880.00	2
	Unit Cost, Dis. Compr.			\$4,580.00 \$3,000.00	2005: 2
	Unit Cost, Storage			\$976,022.73 \$423,579.55	2020: 1
	Ctrl. & Safety Equip.			\$22,320.00 \$22,320.00	2005: 2
	Installed Costs			\$1,508,357.73 \$714,039.55	2020: 4
DepreciableCapital (Indirect)			(Component)		
	[% of Installed Costs]	Site Preparation		6.5%	2
	[% of Installed Costs]	Engineering & Design		3%	3
	[% of Installed Costs]	Process Contingency		\$0.00	2
	[% of Installed Costs]	Project Contingency		5%	55
	[% of Installed Costs]	Other Depreciable Capital		\$0.00	2
	[% of Installed Costs]	One-Time Licensing Fees		\$0.00	3
	[% of Installed Costs]	Up-Front Permitting Costs		3%	3
Var/Nearest	DepreciableCapital	[\$]	(CY)	2005 2035 2050	
Data				\$1,772,320.33 \$838,996.47 \$838,996.47	
Var/Data	LandRequired	[acres]		0	
FixedOM			(Component,CY)	2005 2020	
	Labor Req'd, Maint.			72 72	3
	Labor Costs, Maint.			\$24.20 \$24.20	3
	Labor Costs, Maint.			\$1,742.40 \$1,742.40	
	Labor Req'd, Other			1,232 1,232	
	Labor Costs, Other			\$15.00 \$15.00	3
	Labor Costs, Other			\$18,478.13 \$18,478.13	
	Labor Costs			\$20,220.53 \$20,220.53	
	Overhead and G&A			20% 20%	2
	Property Tax & Insurance			1% 1%	2
	Rent			\$34,848.00 \$34,848.00	52
	Lic., Permits and Fees			0.1% 0.1%	3
	Maint for Maint. & Repairs			1.8% 1.5%	2005: 3
	Other Fees			\$0.00 \$0.00	2020: 5
	Other Fixed O&M Costs			\$0.00 \$0.00	3
Var/Nearest	FixedOM	[\$]	(PY,CY)	2005 2035 2050	
Data				\$110,509.92 \$80,926.54 \$80,926.54	
Var/Nearest	OtherFixed	[\$/year]	(PY,CY)	2005 2035 2050	
Data				\$0.00 \$0.00 \$0.00	
Var/Nearest	FeedstockEfficiency		(Feedstock,CY)	2005 2035 2050	
Data				0.0000 0.0000 0.0000	
	(GJH2/GJFeedstock)	Commercial Natural Gas		0.0000 0.0000 0.0000	
	(GJH2/GJFeedstock)	Industrial Natural Gas		0.0000 0.0000 0.0000	
	(GJH2/GJFeedstock)	Electric Utility Natural Gas		0.0000 0.0000 0.0000	
	(GJH2/GJ)	Commercial Electricity		16.4788 14.7954 14.7954	
	(GJH2/GJ)	Industrial Electricity		0.0000 0.0000 0.0000	
	(GJH2/GJFeedstock)	Utility Steam Coal (Central)		0.0000 0.0000 0.0000	
	(GJH2/GJFeedstock)	Diesel Fuel		0.0000 0.0000 0.0000	
	(GJH2/GJFeedstock)	Biomass		0.0000 0.0000 0.0000	
	(GJH2/GJFeedstock)	Ethanol		0.0000 0.0000 0.0000	
	(GJH2/GJFeedstock)	Methanol		0.0000 0.0000 0.0000	
	(GJH2/GJFeedstock)	Gasoline		0.0000 0.0000 0.0000	
	(GJH2/GJFeedstock)	Steam		0.0000 0.0000 0.0000	
	(GJH2/L)	Cooling Water		0.0000 0.0000 0.0000	
	(GJH2/L)	Demineralized Water		0.0000 0.0000 0.0000	
	(GJH2/L)	Process Water		0.0000 0.0000 0.0000	
	(GJH2/Barrel)	Bio-oil		0.0000 0.0000 0.0000	
	(GJH2/GJFeedstock)	lity Steam Coal (Regional)		0.0000 0.0000 0.0000	
	(GJH2/GJFeedstock)	MSW (1)		0.0000 0.0000 0.0000	
	(GJH2/GJFeedstock)	MSW (2)		0.0000 0.0000 0.0000	
End	OtherVariableOM	[\$/kgH2]	(PY,CY)	2005 2050	
Data				\$0.0000 \$0.0000	
Var/Nearest	ByproductEfficiency		(Byproduct,CY)	2005 2050	
Data				0.0000 0.0000	
End	Emissions	[kg/kgH2]	(Species,CY)	2005 2050	
Var/Nearest				0 0	
Data				0 0	
	Carbon			0 0	
	GHG Equivalents			0 0	
	NOx			0 0	
	SOx			0 0	
	Particulates (PM10)			0 0	
	Mercury			0 0	
End	ReplacementCosts	[\$]	(PY,CY)	2005 2035 2050	
Var/Nearest				\$0.00 \$0.00 \$0.00	
Data				\$0.00 \$0.00 \$0.00	
				\$510,015.00 \$268,140.00 \$268,140.00	3
				\$0.00 \$0.00 \$0.00	
				\$0.00 \$0.00 \$0.00	

Julie_perez:
Source 2 says Compression, Storage and
Dispensing Step Efficiency 93.8%.

Julie_perez:
Source 2 says Storage Design Capacity
(kg) 1193; Storage Usable Capacity (kg)
525.

Based on 4-stage, piston
compressor, 300 psi inlet,
6250 psi outlet.

DOE research goal (2017) + 3 years development time = 2020
This is supposed to be a technology breakthrough, so the
appropriate command is VarNearestof 2020-2020-2005-2035.
With 2035 as a data point, VarNearest will
- use the 2005 value for 2019
- use the 2035 value for 2020

Life of Dispensers & Dispensing compressors is 10
years

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DesignCapacity	CapacityFactor	Location
Location		
DesignCapacity	CapacityFactor	