Proceedings of the 2000 DOE Hydrogen Program Review
NREL/CP-570-28890

PROCESS ANALYSIS WORK FOR THE DOE HYDROGEN PROGRAM - 1999

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Abstract

In 1999, process analysis work conducted at the National Renewable Energy Laboratory for the Department of Energy's Hydrogen Program included updating previous analyses, performing new cost analyses, identifying system integration issues, and conducting the first in a series of life cycle assessments. The goal of this work is to provide direction, focus, and support to the development and introduction of renewable hydrogen through evaluation of the technical, economic, and environmental aspects of hydrogen production and storage technologies. The advantages of performing analyses of this type within a research environment are several fold. First, the economic competitiveness of a project can be assessed by evaluating the costs of a given process compared to the current technology. These analyses can therefore be useful in determining which projects have the highest potential for near-, mid-, and long-term success. Second, the results of a technoeconomic analysis are useful in directing research toward areas in which improvements will result in the largest cost reductions. Finally, as the economics of a process are evaluated throughout the life of the project, advancement toward the final goal of commercialization can be measured. Life cycle assessment (LCA) is used to identify and evaluate the environmental impacts of emissions and resource depletion associated with a specific process. When such an assessment is performed in conjunction with a technoeconomic feasibility study, the total economic and environmental benefits and drawbacks of a process can be quantified. Material and energy balances are used to quantify the emissions, resource depletion, and energy consumption of all processes required to operate the process of interest, including raw material extraction, transportation, processing, and final disposal of products and by-products. The results of this inventory are then used to evaluate the environmental impacts of the process so that efforts can be focused on mitigating negative effects.

The studies that were conducted this year are summarized below. The actual milestone report for each study is available from the authors. Analyses were conducted on the following:

- Update of the analysis of photoelectrochemical hydrogen production to include a Monte Carlo sensitivity analysis (Mann)
- Update of the analysis of hydrogen from biomass to include new experimental data and a Monte Carlo sensitivity analysis (Spath, Lane, Mann, Amos)
- Analysis of hydrogen production from low-Btu coal, including CO_2 sequestration and coalbed methane recovery (Spath and Amos)
- Analysis of hydrogen from PV and wind, with storage required to meet a constant load (Mann, Putsche, Amos)
- Comparison of on-board hydrogen storage options (Lane)
- Study on the use of a reversible fuel cell for storage of wind-generated electricity (Amos)
- Analysis of supercritical water gasification of high-moisture content biomass (Amos)
- LCA of steam methane reforming (Spath and Mann)

Sensitivity Analysis of Photoelectrochemical Hydrogen Production

A 1998 study of the economic viability of photoelectrochemical (PEC) hydrogen production was revised to include advanced sensitivity analysis algorithms. Using Decisioneering's Crystal Ball®, a Microsoft Excel add-in, probability distributions for the major variables were incorporated into the analysis to determine the most likely cost of hydrogen and the uncertainty in that value. Probability distributions were determined from research projections and historical data. This type of detailed sensitivity study presents a clearer picture of the important research elements for success of this technology. Furthermore, the likelihood of research success and progress can be more accurately measured once an analysis of this nature is performed and used as the baseline for future studies.

This type of detailed sensitivity study is often referred to as risk analysis or stochastic modeling. Using various sampling techniques, numerous combinations of variable values can be tested to assess the most likely result. This differs from parametric sensitivity analyses, where only one parameter is varied at a time to assess its affect on the final result. Parametric analyses serve to highlight the most important variables, but do not present best or worse cases that would result from several parameters varying from the base case values. Additionally, the contribution to the uncertainty in the analysis cannot be determined. With parametric analysis, there isn't any opportunity for studying the likelihood that the final answer obtained in the base case will occur given uncertainty in the different inputs. In the context of a hydrogen research project, this type of economic analysis answers questions like: What is the probability that the cost of hydrogen will be less than a given amount? Which parameters contribute the most uncertainty to the final price? What are the likely best and worst cases that could be expected? What is the effect of research goals on the final hydrogen price?

The mean hydrogen selling price result is $5.0/kg ($37.0/GJ, HHV basis) for a 15% internal rate of return (IRR). For a 20% IRR, which may be required for investment in a new technology, the mean hydrogen selling price rose to $6.7/kg. At 10% IRR, the price was $3.5/kg, while the pre-tax production cost (0% IRR) was $1.2/kg. Equity financing and standard U.S. tax structures were assumed. The analysis shows that there is an 80% certainty that the hydrogen will cost less than $41.3/GJ with a 15% after-tax IRR. For a 95% confidence level, the hydrogen will cost less than $46.4/GJ.
The statistical parameters generated by Crystal Ball® serve to describe the variability in this analysis. The standard deviation, or distribution of values around the mean, was about 15% of the mean. This indicates

a fair amount of uncertainty. The kurtosis, or shape of the curve, was 3.84. This is slightly higher than what would be expected of a normal distribution, meaning that the curve is more narrow than the standard. It's important to note that the accuracy of this risk analysis is only as good as the assumptions used to construct the probability distributions.

Determination of the parameters that contribute most to the uncertainty in this analysis allows us to better focus research efforts on areas that will result in cost reductions. As expected, system efficiency has the largest impact on hydrogen selling price, at 30% contribution to variance. Capacity factor holds second place, and demonstrates that the reliability of the system to operate when the sun is shining is crucial to success. Siting the PEC units where there is good solar insolation is important, as demonstrated by its 17.5% contribution to variance. The housing unit, while ranked as fourth, still contributes a very significant 12.4% to the uncertainty of this analysis. Contingency and photocatalyst cost each account for less than 5% of the uncertainty. The support structure, or linear concentrator assembly, is responsible for less than 2%. Other variables accounted for less than 1% each, and 1.3% combined.

Sensitivity Study of the Delivered Cost of Hydrogen from Biomass

The purpose of this analysis was to assess the economic feasibility of producing hydrogen from biomass via two thermochemical processes: 1) gasification followed by reforming of the syngas, and 2) fast pyrolysis followed by reforming of the carbohydrate fraction of the bio-oil. In each process, water-gas shift is used to convert the reformed gas into hydrogen, and pressure swing adsorption is used to purify the product. This study was conducted to incorporate recent experimental advances and any changes in direction from previous analyses. The systems examined are based on the Battelle/FERCO low pressure indirectly-heated biomass gasifier, the Institute of Gas Technology (IGT) high pressure direct-fired gasifier, and fluidized bed pyrolysis followed by coproduct separation. The pyrolysis case assumes a bio-oil feed which is shipped from remote locations to the hydrogen production plant. Following water extraction, the carbohydrate-derived fraction of the bio-oil is reformed while the lignin-derived fraction is sold as a phenol substitute for phenolic resins manufacture.

The delivered cost of hydrogen, as well as the plant gate hydrogen selling price, were determined using a cash flow spreadsheet and Crystal Ball® risk assessment software. Several cases were run for each of the biomass conversion technologies at varying plant sizes and internal rate of return (IRR) values. Three hydrogen production rates were examined for the gasification technologies: 22,737 kg/day, 75,790 kg/day, and 113,685 kg/day. For the pyrolysis case, because some of the bio-oil is used in the production of the coproduct, only the small and medium plant sizes were studied. Even with several remote pyrolysis plants, the feed required for the large plant would likely be more than could be economically secured.

For any given IRR, the plant gate hydrogen selling price is lowest for the pyrolysis case ($1.1-1.3/kg for a 15% after-tax IRR), followed by the Battelle/FERCO gasifier plant ($2.0-2.4/kg for a 15% after-tax IRR), and then the IGT gasifier system ($2.3-2.9/kg for a 15% after-tax IRR). As the plant size increases, the hydrogen selling price decreases due to economy of scale. The delivered cost is important because even if the hydrogen is produced cheaply, the cost to store and transport the hydrogen will make a difference in determining if the hydrogen is economical. Six likely scenarios for hydrogen use were examined, and the cheapest storage and delivery methods were identified. For these six options, storage and delivery adds between $0.1 and $1.7/kg to the plant gate cost, resulting in a delivered cost of hydrogen between $1.3/kg and $4.6/kg (using a 15% after-tax IRR) for all cases studied.

For both of the gasification options (Battelle/FERCO and IGT), the two variables having the largest effect on the uncertainty in the hydrogen selling price are hydrogen production factor and operating capacity. Combined, these two variables account for roughly 51-76% of the uncertainty in the hydrogen selling price depending on the plant size and IRR. For the pyrolysis case, the bio-oil feedstock cost, pyrolytic lignin selling price, and yield of carbohydrate from the bio-oil are the largest contributors to variance, and combine to account for 82-95% of the variability. Roughly 40-44% of the contribution comes from the bio-oil feedstock cost alone.

Hydrogen from Low-Btu Western Coal - Incorporating CO_2 Sequestration and Coalbed Methane Recovery

A hydrogen production process using pressure swing adsorption (PSA) for purification results in a concentrated CO_2 gas stream. In a typical natural gas steam reforming process, this stream is used to fuel the reformer. However, because coal gasification takes place at high temperatures, the synthesis gas contains very little CH_4 and other hydrocarbons, therefore, reforming is not required. An analysis was performed to examine hydrogen production via gasification of low sulfur western coal with CO_2 sequestration of the PSA off gas. This stream is then used to displace methane from unmineable coalbeds and the methane is utilized within the gasification-to-hydrogen system. The work was performed as a collaborative effort between the National Renewable Energy Laboratory and the National Energy Technology Laboratory. The purpose of the analysis was to examine the technoeconomic feasibility, CO_2 emissions, and energy balance of these systems. Several processing schemes, as outlined in Table 1, were evaluated.

Table 1: Cases Examined for Hydrogen from Low-Btu Coal

Case	Title	Description
1	reference case	coal gasification, shift, & H_2 purification
2	CO_2 sequestration only	reference case with CO_2 sequestration only added
3	maximum H_2 production	H_2 production via the syngas, CO_2 sequestration, & additional H_2 production via steam methane reforming of the coalbed methane
4	H_2/power coproduction	H_2 production via the syngas, CO_2 sequestration, & power production via the coalbed methane

For this study, because the hydrogen plant is assumed to be sited far from any users, two likely storage and transportation options were examined: (1) bulk delivery for a distance of 1,610 km (one way) and (2) pipeline delivery with 3 km to nearest infrastructure, no storage, and an additional 1,610 km pipeline, shared by five companies, for delivery to end user. Bulk delivery adds \$8.78/GJ to the plant gate cost and pipeline delivery adds \$4.67/GJ

The economics favor sequestering CO_2, recovering coalbed methane, and making hydrogen or power (case 3 and 4). The plant gate H_2 selling price for these cases are \$8/GJ for maximum H_2 (case 3) and \$14/GJ for H_2/power coproduction (case 4). However, due to the CO_2 emissions generated from the steam methane reformer, additional hydrogen production via natural gas is not necessarily the most environmentally friendly option from a CO_2 standpoint (case 3). Coal fired power plants emit large quantities of CO_2; therefore, optimizing hydrogen production with electricity generation, as in case 4, is a means of lowering the CO_2 emissions from power generation in the U.S. Because of the high temperatures, coal gasification to hydrogen production does not require a steam reforming step, and adding

CO_2 sequestration only (case 2), results in almost no CO_2 being emitted to the atmosphere for a minimal cost. However, for all of the cases examined in the analysis it should be noted that there is much debate about the fate of the sequestered CO_2 and its long term environmental effects.

Hydrogen from PV and Wind, with Storage Required to Meet a Constant Load

A study of the production, storage, and transportation of hydrogen from sunlight and wind was conducted. The basic system was designed to provide enough hydrogen to fuel 100 cars per day at a filling station, with each car requiring approximately 3 kg. Because delivery to the filling station would likely occur at regular intervals, the load was assumed to be constant. Four scenarios were examined for both PV and wind:

- Case 1: the size of the renewable is minimized, while the storage is sized to meet the load each week
- Case 2: the renewable is oversized to meet the load during the worst resource week of the year, while storage requirements are minimized, and the excess electricity is sold over the grid
- Case 3: same as Case 2 except that excess hydrogen rather than excess electricity is produced and sold to a customer other than the filling station
- Case 4: same as Case 1 except that the renewable is located at the filling station, so transportation costs are avoided.

This study had three purposes: (1) To identify possible situations for low-cost hydrogen production from PV and wind, (2) to identify problems associated with using hydrogen to store PV and wind energy, and finally, (3) to test the integration of three models previously developed for hydrogen analysis. Three different models were used to evaluate the four cases. The first model matched hydrogen demand with production from PV and wind, and was used in studies performed for the International Energy Agency. The second model calculates the cost to store and transport hydrogen using different storage devices and transportation modes, over varying distances. The third model was used in an earlier study to determine the cost of hydrogen produced from PV and wind.

Because the model developed for the IEA annex uses actual resource data and existing PV module and wind turbine performance data, present day costs were calculated for these systems. Therefore, as technology improvements in the PV and wind fields improve, the costs of hydrogen will come down. Future studies will incorporate projected performance data into the IEA model. Cost results in this study should be examined for trends rather than projected hydrogen cost. The analysis was performed in three distinct steps. From wind and sunlight resource data, the renewable power output to meet the hydrogen demand was calculated for each case. From these data, the necessary selling price of the hydrogen for an internal rate of return (IRR) of 15% was determined. To this price, the lowest cost to store and transport the hydrogen, was added. Transportation over distances of 10, 100, and 1,000 miles was tested.

Several conclusions about storage and transportation costs with regard to these systems were made. First, liquid storage is favored for long-term storage of hydrogen. For highly variable flows, gas storage should be used because it’s cheaper to oversize a compressor than a liquefier. Finally, rail delivery was found to be the cheapest option for long distances. Transportation costs range between $5.4 and $14.0/GJ of hydrogen delivered. Storage costs were found to be as low as $3.7/GJ for Wind Case 3, but as high as $76.9/GJ for Wind Case 1.

For both the PV and wind systems, the lowest cost hydrogen is obtained in Case 3. The total cost for this case is dominated by the hydrogen production costs; storage and transportation costs are minimal. The lowest delivered hydrogen costs for this case are \$10.4/kg and \$17.3/kg for wind and PV, respectively. The plant-gate selling price of hydrogen in Cases 1 and 4 is slightly lower than in Case 3, but storage costs in these cases are much higher. Case 2, where the electricity not used to produce hydrogen is sold as a byproduct, is less attractive than Case 3. The main reason for this is that hydrogen is worth more than electricity, even if peak prices can be obtained for all of the excess electricity. Additionally, it is conceivable that an electric utility grid, to which the power could be sold, may not be available in all locations where one would like to produce hydrogen from renewables.

In general, and as expected, the hydrogen from the PV systems is more expensive than that from the wind systems. New understanding of the viability of producing hydrogen from PV and wind can be drawn from this study. Principally, systems designed to meet a constant load cannot be economical. Rather, hydrogen sold through larger markets, similar to the way electricity is brokered today, will reduce costs. The important implication of this conclusion is that unless the load matches the resource profile, the economic viability of using hydrogen to meet village and remote energy needs is limited. Minimizing the size of the renewable and using storage to meet the demand results in extremely high storage costs. Sizing the system such that storage costs are minimized creates excess hydrogen and/or electricity, for which a market must exist. Earlier studies have demonstrated that with appropriate grid interaction and moderate technology and cost improvements, hydrogen from PV and wind can be a viable future energy option. Interacting with the grid would reduce the cost of the hydrogen, but would also add a non-renewable energy component to the system. Additionally, this situation will only be possible where an electricity grid is available.

Comparison of On-board Hydrogen Storage Methods

Wide-spread adoption of fuel cell vehicles depends on safe, reliable, and cost-effective hydrogen storage. At the present time, there is no single hydrogen storage option that stands out among the others in terms of a definite alternative to a gasoline storage system in terms of weight, size, maximum speed, mileage range, and cost. The three traditional hydrogen storage methods are compressed hydrogen, liquid hydrogen, and metal hydrides. Several other storage methods are still at the laboratory stage and include carbon adsorption systems, liquid hydrides, nonclassical polyhydride metal complexes (PMCs), glass microspheres, slush hydrogen, and sponge iron. The purpose of this study was to review the characteristics of the storage options found in the literature, and compare them to the current gasoline storage system.

Compressed gas hydrogen storage vessels require a large volume, whereas slush and liquid hydrogen storage vessels require much less space for the same amount of energy. The advantages of a compressed gas system are its simple design, rapid refueling capability, low cost, safety benefits, and the fact that natural gas vessels can be easily adapted for hydrogen storage. In addition to a smaller volume, liquid hydrogen also offers a high hydrogen mass fraction, fast refueling, and sound safety characteristics. However, liquefaction of hydrogen is an expensive process and requires the use of special insulated vessels and pumps for cryogenic on-board storage. Liquid hydrogen boil-off losses can be as high as 2% per day, even in a well-insulated system. Slush hydrogen is similar to liquid hydrogen because it has a high storage density (15% more than a liquid storage system) and requires a cryogenic storage vessel. However, slush hydrogen has specific temperature and pressure requirements, causing this system to be very expensive for passenger vehicle application.

Metal hydrides are extremely safe, but have a high cost, slow refueling time, large weight, and moderate system volume. A metal hydride storage system weighs twice as much as a compressed gas system and four times as much as a liquid hydrogen or gasoline system of an equivalent energy capacity. Carbon adsorption systems operate in a manner similar to metal hydride systems, except hydrogen is bonded to high surface area carbon at extremely low temperatures. Research at the National Renewable Energy Laboratory in single-walled carbon nanotubes is offering great potential for hydrogen storage at ambient conditions. Liquid hydrides have a high volumetric density, are easy to store and transport, but require additional equipment for reforming or oxidation. Nonclassical PMCs may overcome the weight density problem of hydride storage systems and are able to release hydrogen at virtually any rate and temperature. Glass microspheres are porous to hydrogen at high temperature and pressure conditions. These miniature pressure vessels are safe and of moderate weight, but their bulky volume and long refueling time are some of the research obstacles being faced. Sponge iron, a porous form of iron with a high surface area for hydrogen liberating reactions to take place, is safe and has a reasonable cost, however, the weight of iron and water in the system and high temperature requirement for operation do not appear promising for vehicular applications.

Each of these options have benefits and drawbacks, making the decision for an on-board hydrogen storage system very difficult. The three near-term options, gaseous hydrogen, liquid hydrogen, and metal hydrides, have already been tested in passenger vehicles with some success. Both compressed hydrogen and metal hydrides have a much greater volume and weight requirement than a gasoline system, for the same driving range. Liquid hydrogen storage comes very close to a gasoline system's weight and volume, but substantial costs result from liquefaction of the hydrogen. To obtain public acceptance of hydrogen-fueled vehicles, there is a need to further develop hydrogen storage systems in order to bring their weight, volume, vehicle range, and cost to levels comparable to gasoline storage.

Reversible Fuel Cell for Storage of Wind-Generated Electricity

A study was conducted to examine the economic benefit of using a reversible hydrogen bromide fuel cell to store energy generated by wind for sale to the wholesale power market during times when it would produce more revenue. Although the per kWh selling price of electricity was higher in all cases, the annual income from electricity sales was generally lower due to process inefficiencies. When the additional cost of the extra energy storage equipment was considered, the technology was not competitive, even when considering the avoided cost of adding additional transmission line capacity. Electricity prices would need to reach \$0.45/kWh before hydrogen bromide storage would be economical.

A supply-demand curve was constructed using wholesale electricity prices from the New England Power Pool, then hourly wind data were used to determine the amount of wind power that could be produced each hour. A variety of equipment sizes and storage algorithms were considered to optimize revenue and/or power supply efficiency. Hourly demand data for 1998 were used to estimate the electricity sales for each hour of the year and to determine the annual income from electricity sales.

Four different scenarios were examined. In the first case, the costs and income associated with supplying wind power directly to the grid around the clock were determined. This information was used as a baseline comparison of the value of the wind power without any storage system. The analysis showed that selling power on the wholesale market would result in an average selling price of \$0.026/kWh. However, the average selling price would need to be \$0.059/kWh in order to obtain a 15% internal rate of return.

The second case examined storing power produced during off-peak periods and selling the power during peak periods to produce higher revenues. While the average per kWh selling price was higher (as much as $0.032/kWh), the annual revenues were lower because less power was available for sale. This is because using the hydrogen bromide system results in a loss of approximately one third of the energy passing through storage. Power produced from the wind turbine during peak times can, however, flow directly to the grid without going through storage. Even with projected advances in fuel cell technology, the electricity selling price would need to be $0.45/kWh to recover the investment in the storage system and wind turbine.

The last two cases assumed that the power transmission lines from the wind site to the consumer were overloaded and constrained during peak periods, so power could only be transmitted during off-peak times (i.e., nights, weekends and holidays). If no storage is used, power can only be transmitted during off-peak periods and will sell for a very low price. If storage is used, the power can be transmitted during off-peak times and stored near the point of consumption so it can be sold during peak periods without passing though any long-distance transmission lines. These two cases were not favorable because no power from the wind turbines could be used during peak periods and all power sold using the storage system was subject to the one-third efficiency losses. Based on the analysis, construction of new transmission lines is a more economical alternative for providing peak wind power than using a power storage system.

Supercritical Water Gasification of High-Moisture Content Bioamss

Two analyses were performed on the cost of hydrogen production from supercritical water gasification of wet biomass. In the first analysis, the design was based upon information supplied by Professor Michael Antal of the University of Hawaii and Robert Divilio of Combustion Systems, Inc. For the second analysis, some design changes were made to reduce capital and operating costs. However, in both cases, the hydrogen selling price was several times higher than the current price of hydrogen from steam methane reforming.

In the initial analysis using the Antal/Divilio design, three different plant sizes where examined: 9, 90 and 180 Mg biomass/day. The hydrogen selling price with no feed credit or tipping fee ranged from $603/GJ for the smallest plant to $205/GJ for the 180 Mg/day size. The effect of feed cost or credit was then examined for the 180 Mg/day plant. For a feed credit (waste disposal fee) of $22/Mg, the hydrogen selling price was $188/GJ and for a feed cost of $10/Mg, the hydrogen selling price was $214/GJ. Because the capital costs have such a large impact on the hydrogen selling price, the effect of cutting the capital costs in half with a zero feed cost was examined. The resulting hydrogen selling price was $116/GJ. There were a number of concerns with the original Divilio design, such as high electricity consumption, unrealistic cooling water temperatures and the potential for calcium precipitation in the scrubbing section.

In the second analysis, the carbon dioxide scrubber, meant to reduce the load on the hydrogen purification section, was removed and the option of producing power was considered. The 180 Mg/day plant size was used in four different power generation cases with the altered design. The same feed credits and feed costs from the first analysis were used in the second analysis.

In Case 1 of the second study, only hydrogen was produced, with no electricity generation. The hydrogen selling price varied from $89/GJ-$110/GJ, depending on the feed credit/cost. For all analyses, a 20-year plant life was assumed along with a 15% internal rate of return. In Case 2, a combustion turbine was used to generate electricity using the off-gas from the purification module. A $0.04/kWh credit was taken for all electricity generated and sold. The hydrogen selling price for Case 2 ranged from $92/GJ-$114/GJ. For Case 3, additional equipment was added to capture heat from the combustion turbine exhaust in a steam cycle to generate electricity. While the electricity production increased 77% for the same hydrogen production rate, the hydrogen selling price~~s~~ actually increased to $98-$119/GJ because of the higher capital investment. The additional income from electricity production in Case 2 and Case 3 did not justify the added capital expense for the power production equipment.

One last case examined a power production only case, with no hydrogen sales. This was a scenario of interest to Professor Antal and had a lower capital investment because no hydrogen purification equipment was needed. However, the high capital equipment costs associated with the high-pressure, high-temperature supercritical gasification equipment resulted in an electricity selling price that ranged from $0.53-$0.68/kWh, which is eight to ten times higher than the average electricity price of $0.068/kWh in the United States.

Life Cycle Assessment of Hydrogen from Steam Methane Reforming

Although hydrogen is the cleanest burning fuel, it is important to recognize that there are environmental impacts that occur during the production process. The system studied in this life cycle assessment (LCA) is hydrogen production via catalytic steam reforming of natural gas, which is a mature technology and is the route by which most hydrogen is made today. In recognition of the fact that the processes required for the operation of the steam methane reforming (SMR) plant also produce pollutants and consume energy and natural resources, this LCA was performed in a cradle-to-grave manner. Therefore, the emissions, resource consumption, and energy use of the upstream processes necessary to convert the natural gas to hydrogen were included in the study. The system was divided into the following subsystems: natural gas production and distribution, electricity generation, plant construction and decommissioning, hydrogen plant operation, and avoided operations.

The size of the hydrogen plant is 1.5 million Nm^3/day (57 million scfd), which is typical of the size that would be found at today's major oil refineries. The natural gas is reformed in a conventional steam reformer, the resulting synthesis gas is shifted in both high and low temperature shift reactors, and purification is performed using a pressure swing adsorption (PSA) unit. Although the plant requires some steam for the reforming and shift reactions, the highly exothermic reactions result in an excess amount of steam produced by the plant. For the base case, this steam is assumed to be used by some other source. Therefore, the stressors that would have resulted from producing and transporting natural gas and combusting it in a boiler are avoided because the other process/facility is not required to produce this steam. In extracting, processing, transmitting, storing, and distributing natural gas, some is lost to the atmosphere. The base case of this LCA assumed that 3.96% of the natural gas that is produced is lost to the atmosphere.

The operation of the hydrogen plant itself produces very few emissions with the exception of CO_2. On a system basis, CO_2 is emitted in the largest quantity, accounting for 98 wt% of the total air emissions and 77% of the system global warming potential (GWP), defined as a weighted combination of CO_2, CH_4, and N_2O emissions expressed on a CO_2-equivalent basis for a 100 year time frame. Methane, which is primarily emitted as lost natural gas during production and distribution, accounts for 22.3% of the GWP because of its higher radiative forcing. The overall GWP of the system is 13,745 g CO_2-equivalent/kg of hydrogen produced. Table 2 contains a breakdown of the sources, showing that the hydrogen plant itself accounts for 64.7% of the greenhouse gas emissions.

Table 2: Sources of System Global Warming Potential

Source of system greenhouse gases				
Construction & decommissioning [(a)]	Natural gas production & transport	Electricity generation	H_2 plant operation	Avoided operations [(b)]
0.3%	36.6%	2.0%	64.7%	-3.6%

(a) Construction and decommissioning include plant construction and decommissioning as well as construction of the natural gas pipeline.

(b) Avoided operations are those that do not occur because excess steam is exported to another facility.

Other than CO_2, methane is emitted in the next greatest quantity followed by non-methane hydrocarbons (NMHCs), NO_x, SO_x, CO, particulates, and benzene. Most of these air emissions are a result of natural gas production and distribution. In terms of resource consumption, as anticipated, natural gas is used at the highest rate, followed by coal, iron (ore plus scrap), limestone, and oil. There is also a considerable amount of water consumed primarily at the hydrogen plant. This is due to the steam requirements for reforming and shift conversion. The majority of the system waste is generated during natural gas production and distribution. Water emissions are small compared to the other emissions.

The energy balance of the system shows that for every 0.69 MJ of hydrogen produced, 1 MJ of fossil energy must be consumed. From both an environmental and economic standpoint, it is important to increase the energy efficiencies and ratios of any process. This in turn will lead to reduced resources, emissions, wastes, and energy consumption. A sensitivity analysis was performed on the following variables: materials of construction, natural gas losses, operating capacity factor, recycling versus landfilling of materials, natural gas boiler efficiency, hydrogen plant energy efficiency, and hydrogen plant steam balance (no credit for excess steam). Most of the variables examined had no noticeable effect on the results. Future work will involve comparing this study with hydrogen production via other routes such as biomass, wind, and photovoltaics.

Summary

The analyses conducted by NREL's process analysis task for the Hydrogen Program in 1999 served to refine our understanding of the economic feasibility of many research projects, as well as to quantify the environmental impacts of today's primary method of hydrogen production. The use of detailed Monte Carlo sensitivity analyses was demonstrated as a means of determining those parameters that can have the greatest impact on the potential for economic success. Of primary importance, these studies identified those areas of research in which improvements will result in the largest cost reductions. The comparison of various on-board hydrogen storage media to current gasoline storage allows the hydrogen community to make better decisions regarding which storage technology will best meet future transportation needs, as well as giving a consistent basis upon which the Program can assess each option with regard to meeting the Program storage goals. Finally, the life cycle assessment that was conducted on a steam methane reforming system sets the stage for a better understanding of the environmental benefits of hydrogen transportation systems. The net greenhouse gas emissions, energy balance, resource consumption, and other emissions were quantified, and will be compared to results of future LCAs on renewable hydrogen production systems. Because the full life cycle chain was included in the study, upstream processes that are responsible for significant environmental damage can be exposed.

Overall, process analysis at NREL helps the Hydrogen Program methodically assess the applied research portfolio, in order to focus on those projects that have the potential to significantly contribute to the adoption of clean hydrogen systems. Results from the economic studies help researchers concentrate their efforts on those areas that have the greatest impact on cost, such that novel technologies can be commercialized more quickly. Hand-in-hand with cost analysis, LCA studies help the Program, and the hydrogen community as a whole, quantify the environmental status of various hydrogen technologies. Finally, process analysis helps streamline the transition to the hydrogen economy, balancing environmental requirements and economic constraints.