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Technical Report

Life Cycle Assessment of Hydrogen Production via Natural Gas Steam Reforming

Pamela L. Spath
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February 2001 Revision Notes

Notes regarding changes from the November 2000 published version of this report

Pages 7, 10, and 15 contain updated information.

November 2000 Revision Notes

Notes regarding changes from the August 2000 published version of this report

A reduction was made in the amount of natural gas losses. This changed several of the numbers and percentages given throughout the report. However, most of the values varied by a small amount and the conclusions remain the same.

The Executive Summary, pages 8–21 and pages 23–24 contain updated information.

EXECUTIVE SUMMARY

A life cycle assessment (LCA) of hydrogen production via natural gas steam reforming was performed to examine the net emissions of greenhouse gases, as well as other major environmental consequences. LCA is a systematic analytical method that helps identify and evaluate the environmental impacts of a specific process or competing processes. In order to quantify the emissions, resource consumption, and energy use (i.e., environmental stressors), material and energy balances are performed in a cradle-to-grave manner on the operations required to transform raw materials into useful products. Natural gas lost to the atmosphere during production and distribution is also taken into account. Ultimately, this LCA will be compared to other hydrogen production technologies to examine the environmental benefits and drawbacks of the competing systems.

The size of the hydrogen plant was set at 1.5 million Nm^3/day (57 million scfd). The natural gas is reformed in a conventional steam reformer, and the resulting synthesis gas is shifted in both high and low temperature shift reactors; 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 (see section 3.0 for details).

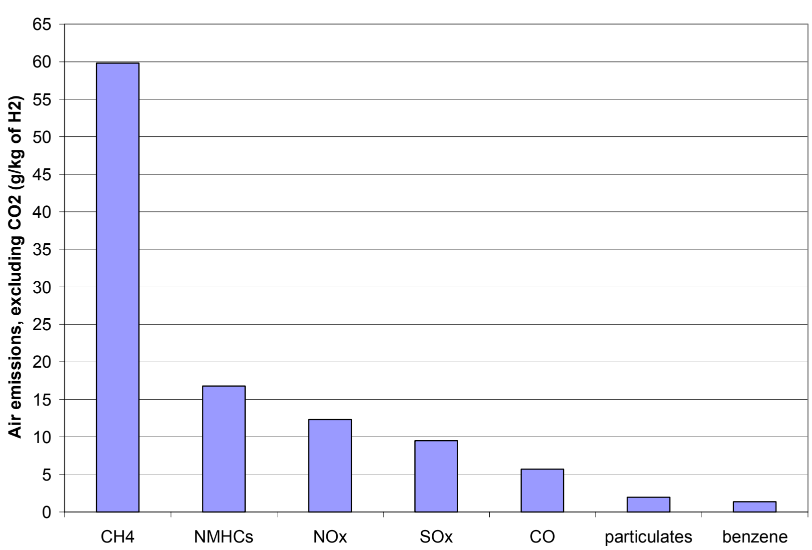
In terms of total air emissions, CO_2 is emitted in the greatest quantity, accounting for 99% (by weight) of the total air emissions. The CO_2 accounts for 89.3% of the system's global warming potential (GWP), defined as a combination of CO_2, CH_4, and N_2O emissions expressed as CO_2-equivalence for a 100 year time frame. Methane accounts for 10.6% of the GWP. The overall GWP of the system is 11,888 g CO_2-equivalent/kg of hydrogen produced; the following table contains a breakdown of the sources showing that the hydrogen plant itself accounts for 74.8% of the greenhouse gas emissions.

Sources of System Global Warming Potential

	total (g/kg of H_2)	% from construction & decommissioning [(a)]	% from natural gas production & transport	% from electricity generation	% from H_2 plant operation	% from avoided operations [(b)]
Greenhouse gas emissions (CO_2-eq)	11,888	0.4%	25.0%	2.3%	74.8%	-2.5%

(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. See section 3.0 for more information about this.

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 (72.3%) is generated during natural gas production and distribution. The remaining waste comes from electricity production (31.0%), and construction and



decommissioning (3.8%). There is also a small amount of waste that is credited to the system due to the avoided operations (-7.1%). Water emissions are small compared to the other emissions.

In examining the energy balance of the system, most of the energy consumed is that contained in the natural gas feedstock. The hydrogen plant energy efficiency is 89.3%, on a higher heating value (HHV) basis (defined as the energy out of the system divided by the energy into the system). Two additional energy efficiencies and two energy ratios, as defined in the following table, were used to examine the energy budget of the system.

Energy Efficiency and Ratio Definitions (LHV basis)

Life cycle efficiency (%)(a)	External energy efficiency (%) (b)	Net energy ratio (c)	External energy ratio (d)
$=\frac{Eh2-Eu-Ef}{Ef}$	$=\frac{Eh2-Eu}{Ef}$	$=\frac{Eh2}{Eff}$	$=\frac{Eh2}{Eff-Ef}$
where: Eh2 = energy in the hydrogen Eu = energy consumed by all upstream processes required to operate the hydrogen plant Ef = energy contained in the natural gas fed to the hydrogen plant Eff = fossil fuel energy consumed within the system (e)			

(a) Includes the energy consumed by all of the processes.
(b) Excludes the heating value of the natural gas feedstock from the life cycle efficiency formula.
(c) Illustrates how much energy is produced for each unit of fossil fuel energy consumed.
(d) Excludes the energy of the natural gas to the hydrogen plant.
(e) Includes the natural gas fed to the hydrogen plant since it is consumed within the boundaries of the system.

Energy Balance Results (LHV basis)

System	Life cycle efficiency	External energy efficiency	Net energy ratio	External energy ratio
H_2 production via natural gas steam reforming	-39.6%	60.4%	0.66	5.1

On a life cycle basis, for one MJ of fossil fuel consumed by the system, 0.66 MJ of hydrogen is produced (LHV basis). This reflects the fact that because natural gas is a non-renewable resource, more energy is consumed by the system than is produced. This number also accounts for the upstream energy used in producing and distributing the natural gas and in producing the electricity required to operate the hydrogen plant.

Finally, 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 LCA. Reducing the hydrogen plant energy efficiency from 89.3% to 80% has the largest effect, with most stressors, including the system GWP, increasing by about 16%. Changes in natural gas losses significantly affect the GWP. The assumed loss in the base case analysis was 1.4% of the total amount removed from the ground. A 0.5% loss reduces the GWP by 5%, while a 4% loss results in a 16% increase from the base case result. NMHC emissions and total system energy consumption are also affected by changes in the natural gas loss. One other variable had a significant effect on the energy balance of the system is the hydrogen plant steam balance. The base case assumes that the excess steam produced at the hydrogen plant is used by another source. If this were not the case, then the system could not be credited for the stressors due to the avoided natural gas production and distribution, and combustion in a boiler. The upstream energy that is avoided in producing and distributing natural gas which would have been combusted in a boiler can no longer be credited to the system. This causes the net energy ratio to decrease from 0.66 to 0.59, and the life cycle efficiency to decrease from -39.6% to -52.8%.

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Units of Measure

Metric units of measure are used in this report. Therefore, material consumption is reported in units based on the gram (e.g., kilogram or megagram), energy consumption based on the joule (e.g., kilojoule or megajoule), and distance based on the meter (e.g., kilometer). When it can contribute to the understanding of the analysis, the English system equivalent is stated in parenthesis. The metric units used for each parameter are given below, with the corresponding conversion to English units.

Mass:	kilogram (kg) = 2.205 pounds
	megagram (Mg) = metric tonne (T) = 1 x 10^6 g = 1.102 ton (t)
Distance:	kilometer (km) = 0.62 mile = 3,281 feet
Area:	hectare (ha) = 10,000 m^2 = 2.47 acres
Volume:	cubic meter (m^3) = 264.17 gallons
	normal cubic meters (Nm^3) = 0.02628 standard cubic feet (scf) at a standard temperature & pressure of 15.6°C (60°F) and 101.4 kPa (14.7 psi), respectively
Pressure:	kilopascals (kPa) = 0.145 pounds per square inch
Energy:	kilojoule (kJ) = 1,000 Joules (J) = 0.9488 Btu
	gigajoule (GJ) = 0.9488 MMBtu (million Btu)
	kilowatt-hour (kWh) = 3,414.7 Btu
	gigawatt-hour (GWh) = 3.4 x 10^9 Btu
Power:	megawatt (MW) = 1 x 10^6 J/s
Temperature:	°C = (°F - 32)/1.8

Hydrogen Equivalents:

1 kg H2	= 423.3 scf gas = 11.126 Nm^3 gas
	= 142 MJ (HHV basis) = 120 MJ (LHV basis)

Abbreviations and Terms

Btu -	British thermal units
CO_2-equivalence-	Expression of the GWP in terms of CO_2 for the following three components CO_2, CH_4, N_2O, based on IPCC weighting factors
DEAM -	Data for Environmental Analysis and Management (also referred to as the TEAM® database)
EIA -	Energy Information Administration
GWP -	global warming potential
HHV -	higher heating value
HTS -	high temperature shift
IPCC-	Intergovernmental Panel on Climate Change
kWh -	kilowatt-hour (denotes energy)
LCA -	life cycle assessment
LHV -	lower heating value
LTS -	low temperature shift
MMSFCD -	million standard cubic feet per day
MW -	megawatt (denotes power)
N_2O -	nitrous oxide
Nm^3 -	normal cubic meters
NMHCs -	non-methane hydrocarbons
NO_x -	nitrogen oxides, excluding nitrous oxide (N_2O)
NREL -	National Renewable Energy Laboratory
PSA -	pressure swing adsorption
SMR -	steam methane reforming
SO_x -	sulfur oxides, including the most common form of airborne sulfur, SO_2
Stressor -	A term that collectively defines emissions, resource consumption, and energy use; a substance or activity that results in a change to the natural environment
Stressor category -	A group of stressors that defines possible impacts
TEAM® -	Tools for Environmental Analysis and Management (software by Ecobalance, Inc.)
U.S. DOE -	United States Department of Energy
U.S. EPA -	Unite States Environmental Protection Agency
wt% -	percentage by weight

1.0 Introduction

Hydrogen is used in a number of industrial applications, with today's largest consumers being ammonia production facilities (40.3%), oil refineries (37.3%), and methanol production plants (10.0%). In 1996, three trillion cubic feet of hydrogen were consumed in the United States (SRI, 1998). International consumption of hydrogen follows a similar trend, with ammonia production accounting for 62.4% of the world's hydrogen, and refining and methanol production consuming 24.3% and 8.7%, respectively. Because such large quantities of hydrogen are required in these instances, the hydrogen is generally produced by the consumer, and the most common method is steam reforming of natural gas.

A life cycle assessment (LCA) of hydrogen production via steam reforming of natural gas was completed by the National Renewable Energy Laboratory (NREL). Although, this study in itself is complete, this is the first in a series of assessments for comparing the environmental benefits and drawbacks of hydrogen production via other routes such as biomass, wind, and photovoltaics. Additionally, other long-term technologies (e.g., photobiological hydrogen production, plasma reforming/oxidation, and carbon nanotube hydrogen storage) can be examined using this analysis tool to explore the possibility of improved environmental consequences.

The primary goal of this LCA is to quantify and analyze the total environmental aspects of producing hydrogen via natural gas steam reforming. In recognition of the fact that upstream 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. For this reason, natural gas production and distribution, as well as electricity generation, were included in the system boundaries. 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. All resources, emissions, and energy flows were inventoried within the boundaries of the system so that the total environmental picture of the system could be depicted.

2.0 Hydrogen Plant Description and Assumptions

The system studied in this 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. The methodology is the same as that used and described in detail in earlier LCAs performed by NREL (Mann and Spath, 1997 and Spath and Mann, 1999). The material and energy balance data for the hydrogen plant were taken from SRI, 1994. This report presents an accurate picture of today's typical SMR plant with one exception; the design does not include a low temperature shift (LTS) reactor. Past analysis (Mann, 1995) and standard practice in the hydrogen production business have shown the addition of an LTS reactor to be economical due to the small amount of additional hydrogen produced. Therefore, for this LCA, the SRI design was modified to include an LTS conversion step. For comparison, a sensitivity analysis was performed to examine the difference in the overall emissions if an LTS reactor were not included in the hydrogen plant design (see section 7.0).

Figure 1 is a block flow diagram of the natural gas steam reforming plant studied in this analysis. Prior to steam reforming, the natural gas is pretreated in a hydrogenation vessel in order to convert any sulfur compounds to H_2S. A small amount of hydrogen, which is recycled from the product stream, is used in this step. The H_2S is then removed in a ZnO bed. After pretreatment, the natural gas and 2.6 MPa (380 psi) steam are fed to the steam reformer. The resulting synthesis gas is then fed to high temperature shift (HTS) and LTS reactors where the water gas shift reaction converts 92% of the CO into H_2. The hydrogen is purified using a pressure swing adsorption (PSA) unit. The reformer is fueled primarily by the PSA off-gas, but a small amount of natural gas (4.4 wt% of the total reformer fuel requirement) is used to supply the balance of the reformer duty. The PSA off-gas is comprised of CO_2 (55 mol%), H_2 (27 mol%), CH_4 (14 mol%), CO (3 mol%), N_2 (0.4 mol%), and some water vapor. The steam reforming process produces 4.8 MPa (700 psi) steam, which is assumed to be exported for use by some other process or facility. Electricity is purchased from the grid to operate the pumps and compressors. Table 1 gives the major performance and design data for the hydrogen plant.

Figure 1: Hydrogen Plant Block Flow Diagram

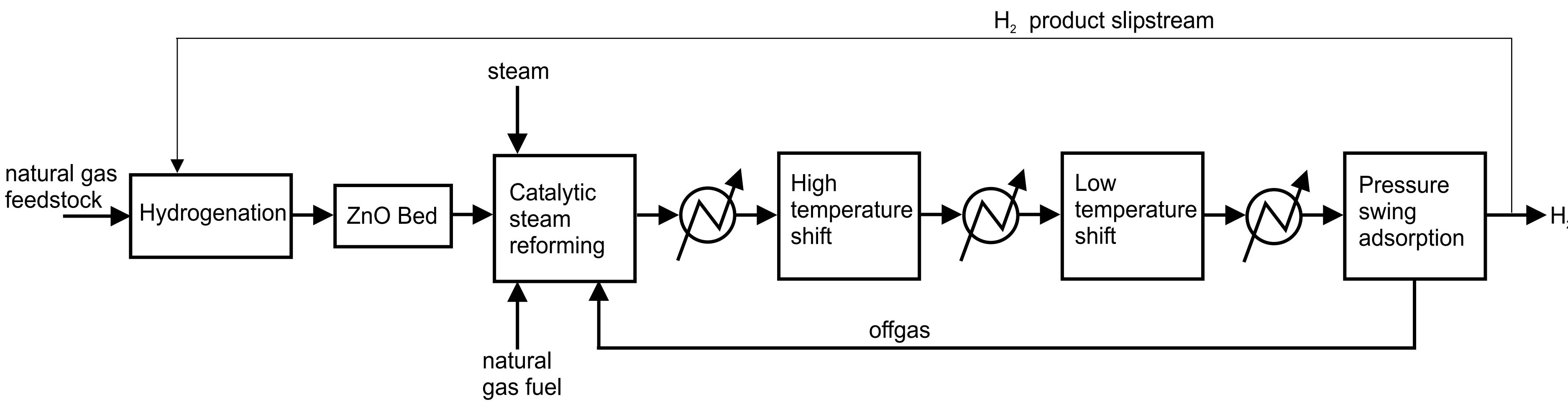


Table 1: Steam Methane Reforming Hydrogen Plant Data

Design Parameter	Data
Plant size (hydrogen production capacity)	1.5 million Nm^3/day (57 million scfd)
Hydrogen purity	Industrial grade (>99.95 mol% H_2)
Average operating capacity factor	90%
Natural gas consumed @ 100% operating capacity	392 Mg/day (feed) 43 Mg/day (fuel)
Steam requirement (2.6 MPa or 380 psi) @ 100% operating capacity	1,293 Mg/day
Steam production (4.8 MPa or 700 psi) @ 100% operating capacity	1,858 Mg/day
Electricity requirement @ 100% operating capacity	153,311 MJ/day
Hydrogen plant energy efficiency (higher heating value (HHV) basis)	89% (defined in text below)

Note: The hydrogen plant efficiency changes if the excess steam can not be utilized by a nearby source. However, this does not change the amount of hydrogen produced by the plant.

The hydrogen plant energy efficiency is defined as the total energy produced by the hydrogen plant divided by the total energy into the plant, determined by the following formula:

$$\frac{\text{energy in product hydrogen} + 4.8\text{ MPa steam energy (exported)}}{\text{natural gas energy} + \text{electricity} + 2.6\text{ MPa steam energy (required)}}$$

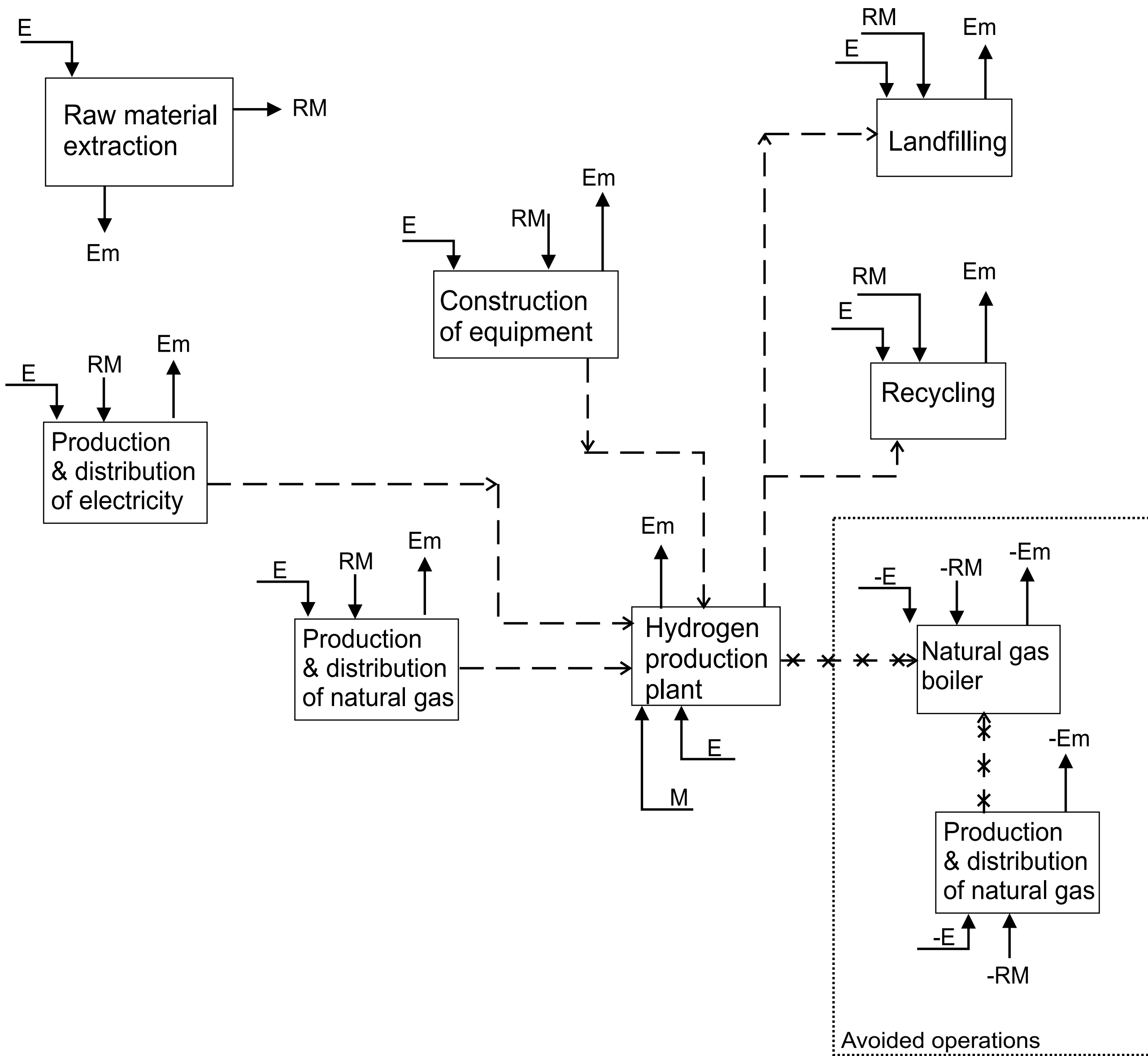
If the steam were not included in the above equation, the conversion efficiency would decrease to 79.2% (i.e., the 2.6 MPa steam is produced internally and the 4.8 MPa steam could not be used by another source). Additionally, if a user could not be found for the 4.8 MPa steam but the 2.6 MPa steam were still included as an energy input, then the hydrogen plant energy efficiency drops to 69.1%. While this would be the preferred operation for a hydrogen plant integrated with petroleum refining, a stand-alone dedicated hydrogen production facility would generate the 2.6 MPa steam internally rather than buy it if a customer for the 4.8 MPa steam could not be found. Additionally, if a customer could not be found for the 4.8 MPa steam, the operator might consider using it to generate electricity for use internally or for sale to the grid. However, it should be noted that given equal opportunity to find customers, a steam byproduct credit is worth more than an electricity byproduct credit because of efficiency losses in converting steam to electricity.

In addition to adding an LTS reactor to the plant design, the reformer flue gas composition was corrected to include NOx, CO, and particulate emissions. Since the reformer furnace is equipped with a low NO_X burner which reduces the emissions to 20 ppm (SRI, 1994), this amount was assumed to be emitted from the hydrogen plant. CO and particulate emissions were obtained from the U.S. Environmental Protection Agency's (EPA) data on natural gas combustion furnaces (U.S. EPA, 1995). The amount of the pollutant is given per the quantity of natural gas fired based on an average natural gas HHV of 8,270 kcal/m^3 (1,000 Btu/scf). The data were ratioed to account for the difference in the heating value of the reformer fuel versus that of natural gas. The resulting CO and particulate emissions from the reformer are 0.084 g/kg H_2 and 0.023 g/kg H_2, respectively.

3.0 System Boundaries and Major Assumptions

The software package used to track the material and energy flows between the process blocks in the system was Tools for Environmental Analysis and Management (TEAM®), by Ecobalance, Inc. Figure 2 shows the boundaries for the system. The solid lines in the figure represent actual material and energy flows; the dotted lines indicate logical connections between process blocks. The dashed lines with Xs through them denote the flows that do not occur because the steam is produced by the hydrogen plant instead of a natural gas boiler. These are the avoided emissions, and thus are taken as credits in the total inventory of the system.

Figure 2: System Boundaries for Hydrogen Production via Natural Gas Steam Reforming



E = energy
Em = emissions
M = materials
RM = raw materials

The stressors associated with natural gas production and distribution, as well as those for electricity generation, were taken from the TEAM® database, known as Data for Environmental Analysis and Management (DEAM). The steps associated with obtaining the natural gas feedstock are drilling/extraction, processing, and pipeline transport. Processing includes glycol dehydration and gas sweetening using the amine process in which sulfur is recovered as elemental sulfur. The emissions associated with each process step in the natural gas production block were obtained through a joint study by Ecobalance, Inc. and the Gas Research Institute (GRI). Electricity production was assumed to be the generation mix of the mid-continental United States, which according to the National Electric Reliability Council, uses 64.7% coal, 5.1% lignite, 18.4% nuclear, 10.3% hydro, 1.4% natural gas, and 0.1% oil; power distribution losses are taken at 7.03%. The stressors associated with this mix were also determined in a cradle-to-grave manner in DEAM, and thus taken into account in this LCA. Some details about the DEAM database modules can be found in the appendix of Mann and Spath (1997).

Because hydrogen production by steam reforming of natural gas is a highly exothermic process more steam is produced by the hydrogen plant than is consumed. The excess steam generated by the plant is assumed to be used by another source. Because this other source does not have to generate steam itself, a credit is taken for the stressors that would have resulted from producing and transporting natural gas and combusting it in a boiler assuming a boiler efficiency of 75%. The emissions for natural gas production are the same as those discussed in the previous paragraph. The natural gas boiler emissions were based on emissions from EPA for natural gas combustion in industrial boilers (U.S. EPA, 1995). A sensitivity analysis was performed to examine the changes in the LCA results for the case where no user for the steam could be found, and therefore credits could not be taken for the excess steam (see section 7.0).

For this study, the plant life was set at 20 years with 2 years of construction. In year one, the hydrogen plant begins to operate; plant construction takes place in the two years prior to this (years negative two and negative one). In year one the hydrogen plant is assumed to operate only 45% (50% of 90%) of the time due to start-up activities. In years one through 19, normal plant operation occurs, with a 90% capacity factor. During the last quarter of year 20 the hydrogen plant is decommissioned. Therefore, the hydrogen plant will be in operation 67.5% (75% of 90%) of the last year.

4.0 Construction Material Requirements

Methods for determining plant construction and decommissioning are the same as those used in NREL's past LCAs (see Mann and Spath, 1997 and Spath and Mann, 1999). Table 2 lists the material requirements used for the plant in this study. A sensitivity analysis was performed to determine how changing these numbers would affect the results (see section 7.0).

Table 2: Hydrogen Plant Material Requirements (Base Case)

Material	Amount required (Mg)
Concrete	10,242
Steel	3,272
Aluminum	27
Iron	40

Because of the large amount of natural gas being consumed, an assumption was made that additional pipelines would be required to move the natural gas from the oil or gas wells to the hydrogen plant. Ullmann's Encyclopedia of Industrial Chemistry (1986) states that typical pipe diameters in the natural gas industry are 60-110 centimeters (23.6-43.3 inches) and Kirk-Othmer's Encyclopedia of Chemical Technology (1993) lists a range of 36-142 centimeters (14.2-55.9 inches). For this analysis, the total length of pipeline transport is assumed to be 4,000 km (2,486 mi), based on information from Ecobalance, Inc. The main pipeline diameter was set at 61 centimeters (24 inches) and is assumed to extend 80% of the total distance or 3,200 km (1,988 mi). Because the main pipeline is shared by many users, only a portion of the material requirement was allocated for the natural gas combined-cycle plant. To determine this percentage, the natural gas required by the hydrogen plant was divided by the total flow through the 61 cm diameter pipe at a pressure drop of 0.05 psi/100 feet (0.001 MPa/100 meters), resulting in a value of 0.9%. The remaining length of the total pipeline, 800 km (498 mi), was also sized so that the pressure drop through the pipe would not exceed 0.05 psi/100 feet (0.001 MPa/100 meters). This resulted in a pipe diameter of 15 centimeters (6 inches). Thus, the total pipeline steel requirement for the hydrogen plant was 12,539 Mg (13,822 tons) assuming a standard wall thickness. The process steps associated with producing the steel (e.g., iron production, electricity generation, steel manufacture, etc.) were included in the analysis, and a sensitivity case was performed using different pipe diameters to determine the effect of material requirements on the results (see section 7.0). Due to a lack of data, the emissions that would result from installing the pipeline were not included in the analysis.

5.0 Natural Gas Composition and Losses

While natural gas is generally thought of as methane, about 5 - 25% of the volume is comprised of ethane, propane, butane, hydrogen sulfide, and inerts (nitrogen, CO_2, and helium). The relative amounts of these components can vary greatly depending on the location of the wellhead. Table 3 gives the composition of the natural gas feedstock used in this analysis, as well as typical pipeline and wellhead compositions. The composition used in this study (first column) assumes that the natural gas is sweetened to remove H_2S to a level of 4 ppmv prior to pipeline transport. Before feeding the natural gas to the reformer, any residual sulfur is removed using a zinc oxide bed.

Table 3: Natural Gas Compositions

Component	Natural gas feedstock used in analysis (a)	Typical pipeline composition (b)	Typical range of wellhead components (mol%) (c)	
	Mol % (dry)	Mol % (dry)	Low value	High value
Methane (CH_4)	94.5	94.4	75	99
Ethane (C_2H_6)	2.7	3.1	1	15
Propane (C_3H_8)	1.5	0.5	1	10
Nitrogen (N_2)	0.8	1.1	0	15
Carbon dioxide (CO_2)	0.5	0.5	0	10
Iso-butane (C_4H_{10})	0	0.1	0	1
N-butane (C_4H_{10})	0	0.1	0	2
Pentanes + (C_5^+)	0	0.2	0	1
Hydrogen sulfide (H_2S)	0	0.0004	0	30
Helium (He)	0	0.0	0	5
Heat of combustion, HHV	53,680 J/g (23,079 Btu/lb)	53,463 J/g (22,985 Btu/lb)	——	——

(a) Taken from SRI, 1994.
(b) Taken from Chemical Economics Handbook (Lacson, 1999) and adjusted to included H_2S.
(c) Taken from Ullmann's Encyclopedia of Industrial Chemistry, 1986.

In extracting, processing, transmitting, storing, and distributing natural gas, some is lost to the atmosphere. Over the past two decades, the natural gas industry and others have tried to better quantify the losses. There is a general consensus that fugitive emissions are the largest source, accounting for about 38% of the total, and that nearly 90% of the fugitive emissions are a result of leaking compressor components (Resch, 1995 and Harrison *et al*, 1997). The second largest source of methane emissions comes from pneumatic control devices, accounting for approximately 20% of the total losses (Resch, 1995). The majority of the pneumatic losses happen during the extraction step. Engine exhaust is the third largest source of methane emissions due to incomplete combustion in reciprocating engines and turbines used in moving the natural gas through the pipeline. These three sources make up nearly 75% of the overall estimated methane emissions (Resch, 1995 and Harrison *et al*, 1997). The remaining 25% comes from sources such as dehydrators, purging of transmission/storage equipment, and meter and pressure regulating stations in distribution lines.

According to the EPA, transmission and storage account for the largest portion of the total methane emissions at 37% followed by extraction at 27%, distribution at 24%, and processing contributing the least at 12% (Harrison *et al*, 1997). In the late 1980s EPA, GRI, and the American Gas Association (AGA) initiated a study which estimated the methane emitted to the atmosphere from U.S. natural gas operations to be 1.4% +/- 0.5% of the gross natural gas produced (Harrison *et al*, 1997). Another publication (Kirchgessner *et al*, 1997) which includes several authors of the EPA/GRI/AGA study, states that numerous estimates of methane emissions are available and that the most commonly cited leakage rates range from 1-4%. Following the EPA/GRI/AGA study, the Natural Gas STAR Program was launched in 1993. It is a voluntary program with the natural gas industry designed to reduce methane emissions through cost-effective measures. The program currently has over 80 partners. Because of this program, the overall amount of methane lost to the atmosphere is actually expected to decrease as the natural gas industry grows. The base case of this LCA assumed that 1.4% of the natural gas that is produced is lost to the atmosphere due to fugitive emissions. To determine the effect that natural gas losses have on the results, and specifically on the systems global warming potential (GWP), a sensitivity analysis was performed on this variable (see section 7.0). The natural gas production module in DEAM was altered so that it could accommodate different natural gas loss rates.

6.0 Results

The results of this LCA, including air emissions, energy requirements, resource consumption, water emissions, and solid wastes, are presented here. The functional unit, also known as the production amount that represents the basis for the analysis, was chosen to be the net amount of hydrogen produced. Most values are given per kg of hydrogen, averaged over the life of the system so that the relative contribution of stressors from the various operations could be examined. Because the resource consumption, emissions, and energy use are functions of the size of the plant and the technology, care should be taken in scaling results to larger or smaller facilities, or applying them to other hydrogen production systems.

6.1 Air Emissions

In terms of total air emissions, CO_2 is emitted in the greatest quantity, accounting for 99 wt% of the total air emissions. The vast majority of the CO_2 (84%) is released at the hydrogen plant. Table 4 is a list of the major air emissions as well as a breakdown of the percentage of each emission from the following subsystems: construction and decommissioning, natural gas production and transport, electricity generation, hydrogen plant operation, and avoided operations. After CO_2, methane is emitted in the next greatest quantity followed by non-methane hydrocarbons (NMHCs), NO_x, SO_x, CO, particulates, benzene, and N_2O. Overall, other than CO_2, most of the air emissions are a result of natural gas production and distribution. Very few emissions, other than CO_2, come from the hydrogen plant operation itself. The CH_4 is primarily a result of natural gas fugitive emissions which are 1.4% of the gross natural gas production for the base case. Although not shown in Table 4, the CH_4 emitted during production and distribution of natural gas is 76% of the total system methane emissions.

Table 4: Average Air Emissions

Air Emission	System total (g/kg of H_2)	% of total in this table	% of total excluding CO_2	% of total from construction & decommissioning	% of total from natural gas production & transport	% of total from electricity generation	% of total from H_2 plant operation	% of total from avoided operations
Benzene (C_6H_6)	1.4	< 0.0%	1.3%	0.0%	110.9%	0.0%	0.0%	-10.9%
Carbon Dioxide (CO_2)	10,620.6	99.0%		0.4%	14.8%	2.5%	83.7%	-1.5%
Carbon monoxide (CO)	5.7	0.1%	5.3%	2.0%	106.3%	0.7%	1.4%	-10.4%
Methane (CH_4)	59.8	0.6%	55.7%	< 0.0%	110.8%	< 0.0%	0.0%	-10.9%
Nitrogen oxides (NO_X as NO_2)	12.3	0.1%	11.0%	1.8%	90.3%	9.5%	7.3%	-8.9%
Nitrous oxide (N_2O)	0.04	< 0.0%	< 0.0%	7.3%	37.6%	58.7%	0.0%	-3.7%
Non-methane hydrocarbons (NMHCs)	16.8	0.2%	15.6%	1.7%	89.8%	14.5%	0.0%	-6.0%
Particulates	2.0	< 0.0%	1.8%	64.5%	25.2%	11.6%	1.1%	-2.5%
Sulfur oxides (SO_X as SO_2)	9.5	0.1%	8.8%	13.5%	68.3%	24.9%	0.0%	-6.7%

Note: Construction and decommissioning include plant construction and decommissioning as well as construction of the natural gas pipeline.

6.2 Greenhouse Gases and Global Warming Potential

Although CO_2 is the most important greenhouse gas and is the largest emission from this system, quantifying the total amount of greenhouse gases produced is the key to examining the GWP of the system. The GWP of the system is a combination of CO_2, CH_4, and N_2O emissions. The capacity of CH_4 and N_2O to contribute to the warming of the atmosphere is 21 and 310 times higher than CO_2, respectively, for a 100 year time frame according to the Intergovernmental Panel on Climate Change (IPCC) (Houghton, *et al*, 1996). Thus, the GWP of a system can be normalized to CO_2-equivalence to describe its overall contribution to global climate change. The GWP, as well as the net amount of greenhouse gases, are shown in Table 5. It is evident from this table that CO_2 is the main contributor, accounting for 89.3% of the GWP for this specific system. However, it is important to note that the natural gas lost to the atmosphere during production and distribution causes CH_4 to affect the system's GWP. Although the amount of CH_4 emissions is considerably less than the CO_2 emissions on a weight basis (10,621 g of CO_2/kg of H_2 versus 60 g of CH_4/kg of H_2), because the GWP of CH_4 is 21 times that of CO_2, CH_4 accounts for 10.6% of the total GWP.

Table 5: Greenhouse Gases Emissions and Global Warming Potential

	Emission amount (g/kg of H_2)	Percent of greenhouse gases in this table (%)	GWP relative to CO_2 (100 year IPCC values)	GWP value (g CO_2-equivalent/kg of H_2)	Percent contribution to GWP (%)
CO_2	10,621	99.4	1	10,621	89.3
CH_4	60	0.6	21	1,256	10.6
N_2O	0.04	0.0003	310	11	0.1
GWP	N/A	N/A	N/A	11,888	N/A

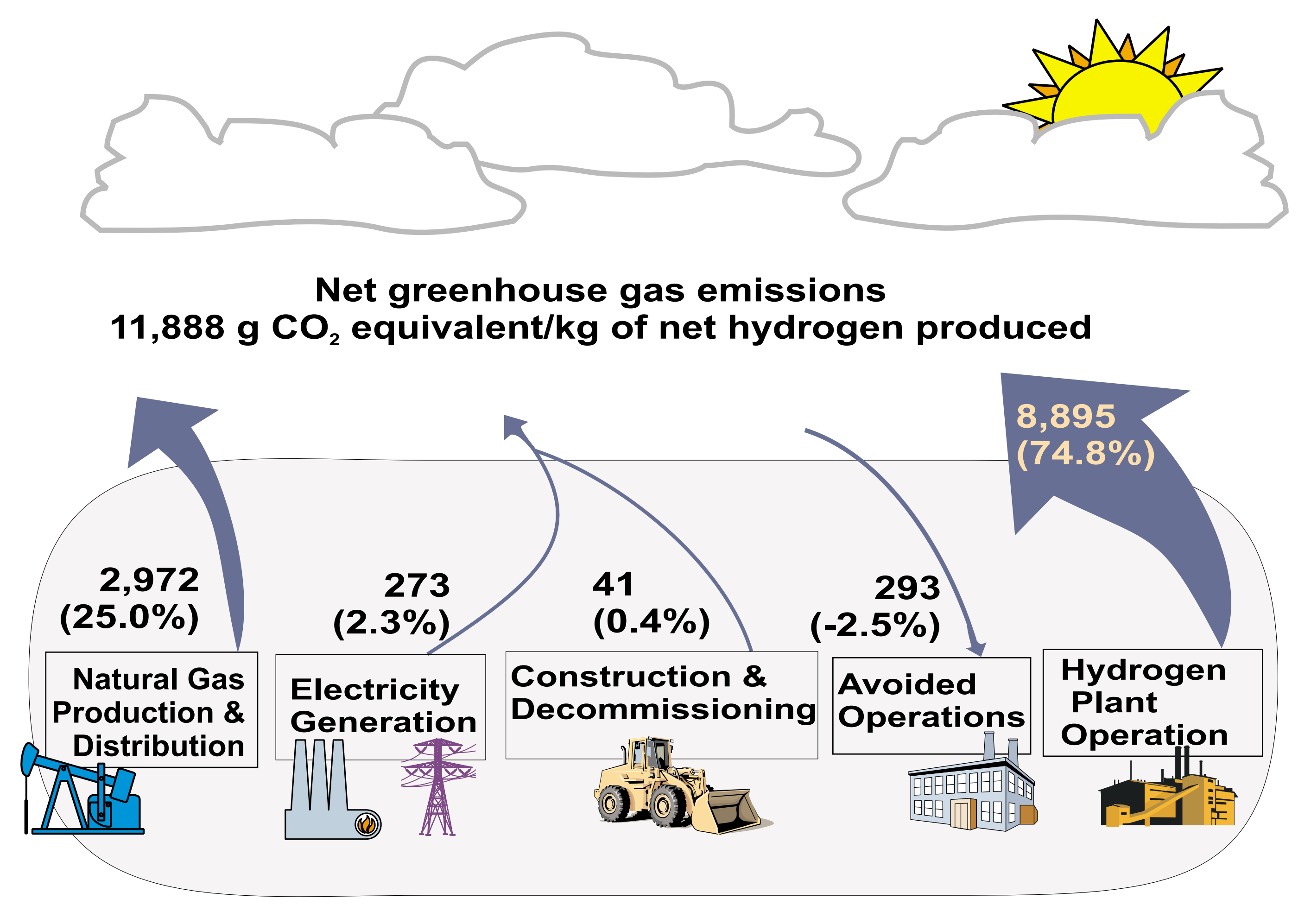
Note: Additional figures after the decimal than those that are significant are presented so that the emissions would not appear as being zero.

Figure 3 shows how the CO_2-equivalent emissions are divided among natural gas production and distribution, electricity generation, plant construction and decommissioning and pipeline construction, hydrogen plant operation, and avoided operations. The majority comes primarily from the hydrogen plant, which accounts for 74.8% of the overall GWP of the system. This is followed by natural gas production and distribution which contributes 25.0% to the GWP. Again, this is due to the amount of the natural gas lost to the atmosphere. Changing the amount of natural gas lost will have a significant affect on the system's GWP and this can be seen in the sensitivity analysis in section 7.0.

6.3 Energy Consumption and System Energy Balance

Energy consumption is an important part of LCA. The energy consumed within the system boundaries results in resource consumption, air and water emissions, and solid wastes. Table 6 shows the energy balance for the system and because of its magnitude, the natural gas energy is listed separately. Most of the energy consumed, about 87%, is that contained in the natural gas fed to the steam reformer. As discussed in section 3.0, because of the excess steam produced at the hydrogen plant, a credit is taken for the stressors associated with producing and transporting natural gas and then combusting it in a boiler. Therefore, the non-feedstock energy from the avoided operations steps is negative.

Figure 3: Life Cycle GWP (CO_2-equivalent)



Avoided Operations = steam production from a natural gas boiler and natural gas production & distribution required to obtain the natural gas

Table 6: Average Energy Requirements (LHV basis)

	System total energy consumption (MJ/kg H_2)	% of total in this table	% of total from construction & decommissioning	% of total from natural gas production & distribution	% of total from electricity generation	% of total from avoided operations
Energy in the natural gas to hydrogen plant	159.6	87.1%	N/A	100.0%	N/A	N/A
Non-feedstock energy consumed by system (*)	23.6	12.9%	2.4%	169.8%	17.0%	-89.3%
Total energy consumed by system	183.2	N/A	N/A	N/A	N/A	N/A

* Excludes the energy in the natural gas feedstock energy but includes the energy in the natural gas lost to the atmosphere during natural gas production.

The hydrogen plant energy efficiency is 89.3%, on an HHV basis (defined in section 2.0). Table 7 contains four additional terms for evaluating the energy balance of the system. The results are in Table 8.

Table 7: Energy Efficiency and Ratio Definitions (LHV basis)

Life cycle efficiency (%)(a)	External energy efficiency (%) (b)	Net energy ratio (c)	External energy ratio (d)
$=\frac{Eh2-Eu-Ef}{Ef}$	$=\frac{Eh2-Eu}{Ef}$	$=\frac{Eh2}{Eff}$	$=\frac{Eh2}{Eff-Ef}$
where: Eh2 = energy in the hydrogen Eu = energy consumed by all upstream processes required to operate the hydrogen plant Ef = energy contained in the natural gas fed to the hydrogen plant Eff = fossil fuel energy consumed within the system (e)			

(a) Includes the energy consumed by all of the processes.
(b) Excludes the heating value of the natural gas feedstock from the life cycle efficiency formula.
(c) Illustrates how much energy is produced for each unit of fossil fuel energy consumed.
(d) Excludes the energy of the natural gas to the hydrogen plant.
(e) Includes the natural gas fed to the hydrogen plant since it is consumed within the boundaries of the system.

Table 8: Energy Balance Results (LHV basis)

	Base case result
Life cycle efficiency	-39.6%
External energy efficiency	60.4%
Net energy ratio	0.66
External energy ratio	5.1

The energy in the natural gas is greater than the energy content of the hydrogen produced. Therefore, the life cycle efficiency is negative. This reflects the fact that because natural gas is a non-renewable resource, more energy is consumed by the system than is produced. In calculating the external energy efficiency, the energy content of the natural gas is not included, making the result of this measure positive. The difference between the hydrogen plant efficiency and the external energy efficiency quantifies how much energy is used in upstream processes. The results also show that for every MJ of fossil fuel consumed by the system, 0.66 MJ of hydrogen are produced (LHV basis). Although the life cycle efficiency and net energy ratio are more correct measures of the net energy balance of the system, the external measures are useful because they expose the rate of energy consumption by the upstream process steps. Disregarding the energy in the natural gas feedstock, the majority of the total energy consumption comes from natural gas production and distribution (see Table 6), which can be further broken up into sub-processes: natural gas extraction, processing, transmission, storage, and distribution. Analyzing each of these steps, it was found that the large amount of energy consumed in natural gas production is specifically from the natural gas extraction and transport steps. Conversely, the energy credit from the avoided operations is also a result of natural gas production and distribution. Note that in general, higher efficiencies and energy ratios are desired for any process, not only in terms of economics, but in terms of reduced resources, emissions, wastes, and energy consumption.

6.4 Resource Consumption

Fossil fuels, metals, and minerals are used in converting natural gas to hydrogen. Excluding water, Table 9 shows the major resource consumption requirements for the system. As expected, natural gas is used at the highest rate, accounting for 94.5% of the total resources on a weight basis, followed by coal at 4.1%, iron (ore plus scrap) at 0.6%, limestone at 0.4%, and oil at 0.4%. The iron and limestone is used in the construction of the power plant and pipeline. The majority of the oil consumption (60.9%) comes from natural gas production and distribution while most of the coal is consumed to produce the electricity needed by the hydrogen plant.

Table 9: Average Resource Consumption

Resource	total (g/kg H_2)	% of Total in this table	% of total from construction & decommissioning	% of total from natural gas production & transport	% of total from electricity generation	% of total from avoided operations
Coal (in ground)	159.2	4.1%	7.1%	17.4%	77.2%	-1.7%
Iron (Fe, ore)	10.3	0.3%	100.0%	0.0%	0.0%	0.0%
Iron scrap	11.2	0.3%	100.0%	0.0%	0.0%	0.0%
Limestone ($CaCO_3$, in ground)	16.0	0.4%	100.0%	0.0%	0.0%	0.0%
Natural gas (in ground)	3,642.3	94.5%	< 0.0%	110.8%	0.1%	-10.9%
Oil (in ground)	16.4	0.4%	30.0%	60.8%	15.1%	-6.0%

Table 10 is a breakdown of the water consumption for the system. The majority of the water is consumed at the hydrogen plant. Table 11 divides the hydrogen plant usage into that required for reforming and shift and that used to produce additional steam. The smaller percentage (24.0%) is the amount that is consumed during the conversion of natural gas to hydrogen while the higher percentage (71.2%) is a result of the excess steam production.

Table 10: Water Consumption

	total (liters/kg H_2)	% of total from construction & decommissioning	% of total from natural gas production & transport	% of total from electricity generation	% of total from H_2 plant operation	% of total from avoided operations
Water consumed	19.8	3.6%	1.3%	< 0.0%	95.2%	-0.1%

Table 11: Breakdown of Hydrogen Plant Water Consumption

	Amount consumed (liters/kg H_2)	% of total water consumption
Water consumed in reforming & shift reactions	4.8	24.0%
Water consumed in 4.8 MPa steam production	14.1	71.2%
Total water consumption from hydrogen plant	18.8	95.2%

6.5 Water Emissions

Similar to the findings of previously performed LCAs (Mann and Spath, 1997; and Spath and Mann, 1999), the total amount of water pollutants was found to be small compared to other emissions. Therefore, a list of the individual components and their quantities is not reported in this document. The total amount of water pollutants for this study equals 0.19 g/kg of H_2 with the primary pollutant being oils (60%) followed by dissolved matter (29%). It is interesting to note that the water pollutants come primarily from the material manufacturing steps required for pipeline and plant construction.

6.6 Solid Waste

The waste produced from the system is miscellaneous non-hazardous waste, totaling 201.6 g/kg of hydrogen produced. Table 12 contains a breakdown of the percentage of waste from each of the subsystems. The majority (72.3%) comes from natural gas production and distribution. Breaking this down further, pipeline transport is responsible for 50% of the total system waste and natural gas extraction is the second largest waste source, accounting for 22% of the total. Although the majority of the pipeline compressors are driven by reciprocating engines and turbines which are fueled by the natural gas, there are some electrical machines and electrical requirements at the compressor stations. The waste due to pipeline transport is a result of this electricity requirement. The remaining system waste comes from the grid electricity (31.0%) required to operate the hydrogen plant and from construction and decommissioning (3.8%) (the electricity generation mix is described in section 3.0.). Since there are two process steps using a considerable amount of electricity (natural gas pipeline transport and the hydrogen production plant), almost 80% of the system waste is a result of power generation. Because most of the electricity in the U.S. is generated from coal-fired power plants (51.7%, U.S. DOE, July 1998), the majority of the waste will be in the form of coal ash and flue gas clean-up waste. There is also a small credit for the waste avoided during natural gas production, distribution, and combustion (-7.1%). Although this study did not account for any solid wastes from the hydrogen plant itself, it should be noted that the only waste stream from the plant will be a small amount of spent catalyst generated from the reformer and shift reactors about every 5 years.

Table 12: Solid Waste Generation

	total (g/kg H_2)	% of total from construction & decommissioning	% of total from natural gas production & transport	% of total from electricity generation	% of total from avoided operations
Waste generated	201.6	3.8%	72.3%	31.0%	-7.1%

7.0 Sensitivity Analysis

A sensitivity analysis was conducted to examine the effects of varying the base case assumptions for several parameters. These parameters and their changes are shown in Table13. Each parameter was changed independently of all others so that the magnitude of its effect on the base case could be assessed. Therefore, no single sensitivity case represents the best or worst situation under which these systems might operate.

Table 13: Variables Changed in Sensitivity Analysis

Variable	Base case value	Sensitivity analysis cases	
Amount of materials required for plant construction	see section 4.0 for details	decrease by 50%	increase by 50%
Amount of materials required for pipeline construction	see section 4.0 for details	decrease by 20%	increase by 20%
Natural gas losses (% of gross production)	1.4%	0.5%	4%
Operating capacity factor	0.90	0.80	0.95
Materials recycled versus materials landfilled	75/25	50/50	
Shift reactors	HTS and LTS	no LTS (HTS only)	
Natural gas boiler efficiency	75%	64%	
Hydrogen plant energy efficiency (HHV basis)	89.3%	80%	
Steam balance (credit/debit)	credit for excess steam (4.8 MPa); debit for 2.6 MPa steam (see section 2.0 & 3.0)	no credit for excess steam (4.8 MPa); assumed 2.6 MPa steam made internally	

Individual energy and material balances could not be obtained for the natural gas production and distribution steps (extraction, glycol dehydration, amine gas sweetening, and pipeline transport), therefore a sensitivity analysis which varied the wellhead gas composition could not performed. However, from the DEAM database a breakdown of the stressors show that the majority come from extraction and pipeline transport and only a small fraction are the result of separation, dehydration, and sweetening.

Table 14 shows the percent change from the base case in the major resources, emissions, waste, and energy consumption. Reducing the hydrogen plant energy efficiency 9.3 percentage points has the largest effect on the results, with the stressors increasing by about 16%. Changing the natural gas losses affects not only the methane emitted from the system, but also the amount of NMHC emissions because 4.2% of the natural gas lost to the atmosphere is ethane and propane. The loss assumed in the base case was 1.4% of the amount removed from the ground. For a 0.5% natural gas loss the CH_4 emissions decrease from the base case result by about 49% and the NMHCs decrease by about 19%. For a 4% loss the CH_4 emissions increase by 147% and the NMHCs increase by about 57% (see Figure 4 as well as a discussion in the next paragraph for the effect that the CH_4 has on the system's GWP). Additionally, because there is a large amount of energy consumed in extracting the natural gas, the energy consumption for the 0.5% loss case decreases by 7% and increases by 22% for the 4% loss case.

It is also important to note that if the excess steam produced at the hydrogen plant can not be used by another source, then the credit for the stressors due to the avoided natural gas production, distribution, and combustion can not be applied to the overall system emissions. This would cause the natural gas consumption to go up along with several of the system air emissions. Benzene, CO, and CH_4 all increase by about 11% each. Additionally, the non-feedstock energy consumption would also increase significantly (89%). Although this increase is large, it is important to note that the majority of the energy consumption is still due to the natural gas feedstock. However, the change in energy consumption will affect the energy efficiency and energy ratio numbers as discussed in the following paragraph (also see Figures 5 - 8).

Figures 4 through 8 display the resulting GWP, life cycle efficiency, external energy efficiency, net energy ratio, and external energy ratio, respectively, for the sensitivity analysis. For comparison, the base case results are shown on these figures. Reducing the plant energy efficiency from 89.3% to 80% increases the GWP of the system by 16%. This variable also has a large effect on the energy balance of the system causing the life cycle efficiency to drop about 25% and the net energy ratio to decrease from 0.66 to 0.57. The only other variable that has a significant effect on the system's GWP is a change in the natural gas losses. Reducing the natural gas losses to 0.5% reduces the GWP by about 4% and increasing the natural gas losses to 4% increases the GWP by 16% (again, refer to Figure 4). This variable also slightly affects the system energy balance. For the 4% natural gas loss case, the net energy ratio decreases 3% (0.66 to 0.64) and the life cycle efficiency decreases 8% (-39.6% to -42.9%). Additionally, two other variables have a noticeable effect on the energy balance of the system: the case where no steam credit or debit is taken and the case where the boiler efficiency is reduced to 64%. For the steam case, it is assumed that the hydrogen plant produces the amount of steam required for the process but does not have a source nearby which can utilize the excess steam. The upstream energy that is avoided in producing and distributing natural gas which would have been combusted in a boiler can no longer be credited to the system. This causes the net energy ratio to decrease by 10% (0.66 to 0.59) and the life cycle efficiency to decrease from -39.6% to -52.8%. Changing the boiler efficiency has only a slight effect on the energy balance with the net energy ratio increasing 2% (0.66 to 0.67) and the life cycle efficiency increasing 6% (-39.6% to -37.3%).

Table 14: Sensitivity Analysis Results - Percent change from base case

Stressor	-50% const. materials	+50% const. materials	-20% pipeline materials	+20% pipeline materials	0.5% nat. gas loss	4% nat. gas loss	0.8 op capacity	0.95 op capacity	50/50 recycle/ landfill	No LTS	64% boiler eff.	80% energy eff.	no stm credit or debit
Coal	-0.91%	0.91%	-1.06%	1.06%	-0.14%	0.43%	0.89%	-0.37%	0.15%	-0.68%	-0.29%	15.60%	1.71%
Iron ore	-4.30%	4.30%	-18.28%	18.28%	0.00%	0.00%	12.50%	-5.26%	5.41%	0.00%	0.00%	15.60%	0.00%
Iron scrap	-4.22%	4.22%	-18.31%	18.31%	0.00%	0.00%	12.50%	-5.26%	5.25%	0.00%	0.00%	15.60%	0.00%
Limestone	-47.04%	47.04%	-1.18%	1.18%	0.00%	0.00%	12.50%	-5.26%	0.35%	0.00%	0.00%	15.60%	0.00%
Natural gas	0.00%	0.00%	0.00%	0.00%	-0.90%	2.71%	0.00%	0.00%	0.00%	0.90%	-1.87%	15.60%	10.88%
Oil	-12.73%	12.73%	-0.92%	0.92%	-0.50%	1.49%	3.76%	-1.58%	0.04%	0.33%	-1.03%	15.60%	5.98%
Water consumed	-0.17%	0.17%	-0.66%	0.66%	-0.01%	0.03%	0.45%	-0.19%	0.19%	0.01%	-1.25%	15.60%	0.13%
Benzene (C_6H_6)	0.00%	0.00%	0.00%	0.00%	-0.90%	2.71%	0.00%	0.00%	0.00%	0.90%	-1.87%	15.60%	10.89%
Carbon Dioxide (CO_2)	-0.08%	0.08%	-0.0%	0.04%	-0.13%	0.38%	0.05%	-0.02%	0.01%	0.81%	-0.25%	15.60%	1.46%
Carbon Monoxide (CO)	-0.81%	0.81%	-0.07%	0.07%	-0.87%	2.60%	0.24%	-0.10%	0.00%	0.91%	-1.80%	15.60%	10.45%
Non-methane Hydrocarbons	-0.24%	0.24%	-0.24%	0.24%	-19.14%	57.30%	0.21%	-0.09%	0.04%	0.57%	-1.03%	15.60%	5.99%
Methane (CH_4)	-0.01%	0.01%	0.00%	0.00%	-49.05%	146.87%	0.00%	0.00%	0.00%	0.90%	-1.87%	15.60%	10.89%
Nitrogen Oxides (NO_X as NO_2)	-0.73%	0.73%	-0.08%	0.08%	-0.74%	2.20%	0.23%	-0.10%	0.00%	0.57%	-1.52%	15.60%	8.87%
Nitrous Oxide (N_2O)	-1.12%	1.12%	-1.02%	1.02%	-0.31%	0.92%	0.92%	-0.39%	0.11%	-0.32%	-0.64%	15.60%	3.70%
Particulates (unspecified)	-28.32%	28.32%	-1.58%	1.58%	-0.21%	0.62%	8.07%	-3.40%	0.44%	0.12%	-0.43%	15.60%	2.48%
Sulfur Oxides (SO_X as SO_2)	-6.18%	6.18%	-0.22%	0.22%	-0.56%	1.67%	1.68%	-0.71%	0.01%	0.29%	-1.15%	15.60%	6.71%
Non-hazardous miscellaneous waste	-0.54%	0.54%	-0.55%	0.55%	-0.59%	1.77%	0.48%	-0.20%	0.59%	0.26%	-1.22%	15.60%	7.10%
Non-feedstock energy consumed by system (includes energy in natural gas loss energy)	-0.58%	0.58%	-0.25%	0.25%	-7.38%	22.09%	0.30%	-0.13%	0.03%	1.19%	-15.34%	15.60%	89.25%
Energy in natural gas to hydrogen plant	0.00%	0.00%	-0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.81%	0.00%	15.60%	0.00%
Total energy consumed by system	-0.08%	0.08%	-0.03%	0.03%	-0.95%	2.85%	0.04%	-0.02%	0.00%	0.86%	-1.98%	15.60%	11.51%

Figure 4: Sensitvity Results for GWP

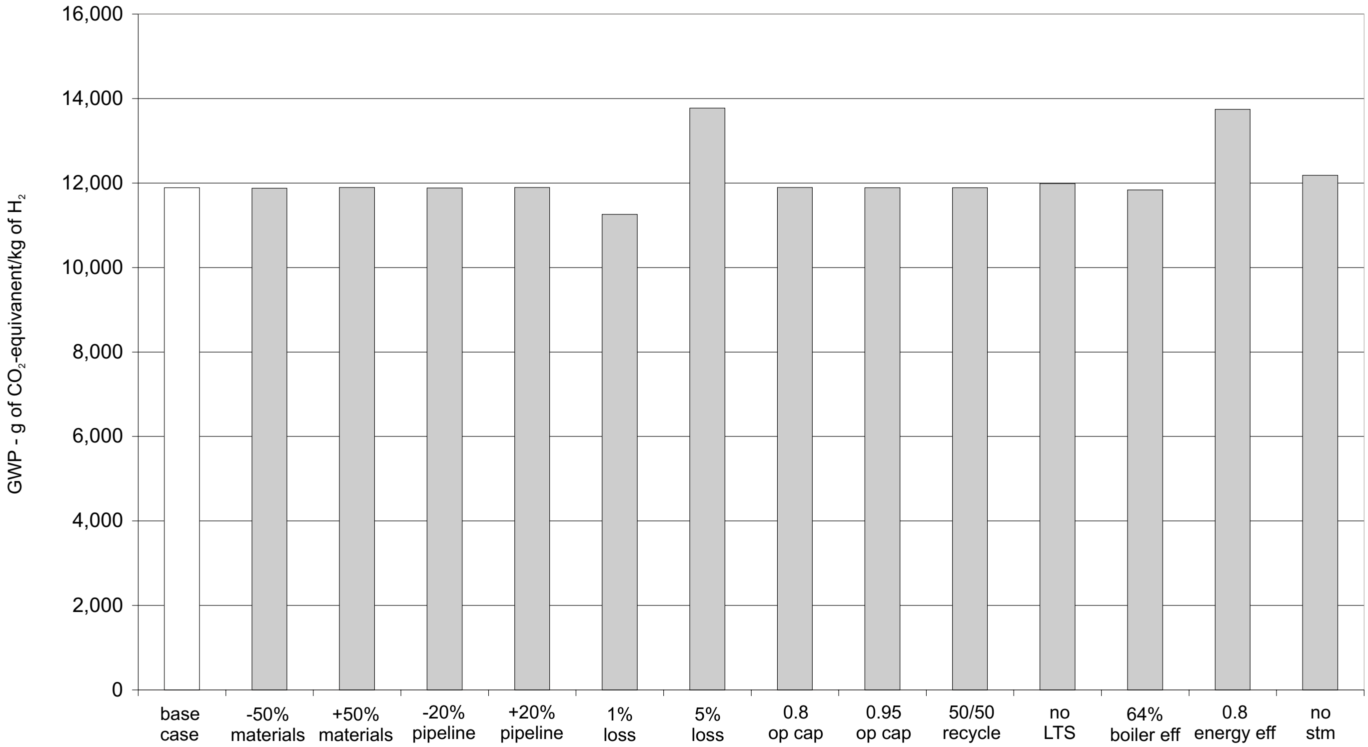


Figure 5: Sensitivity Results for Life Cycle Efficiency

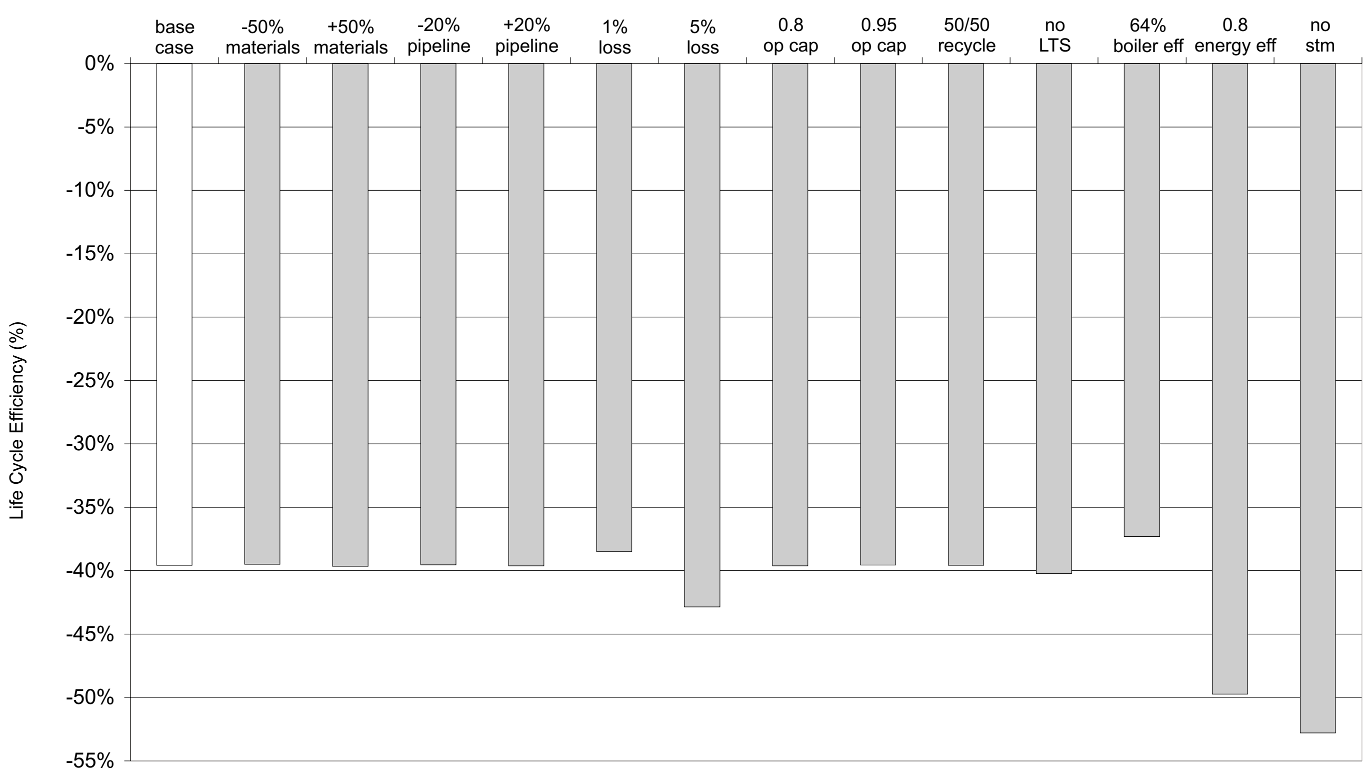


Figure 6: Sensitivity Results for External Energy Efficiency

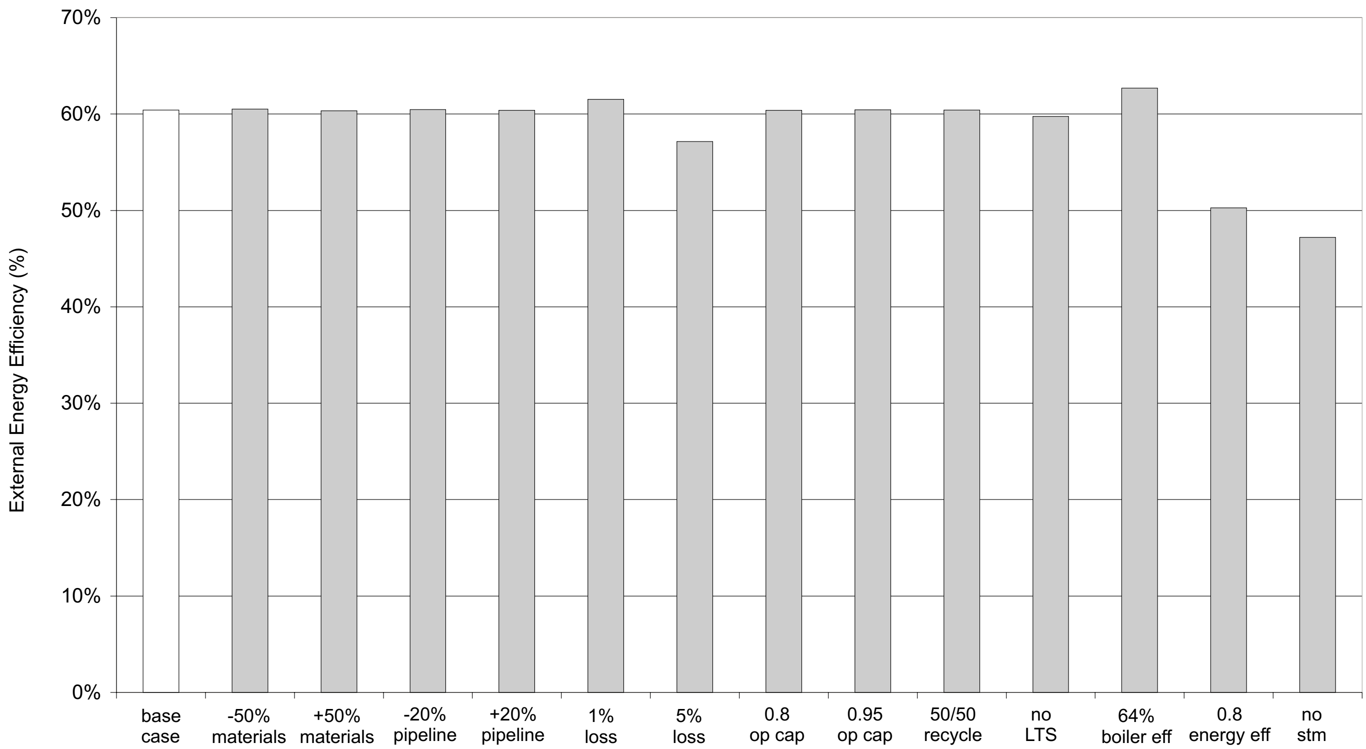


Figure 7: Sensitivity Results for Net Energy Ratio

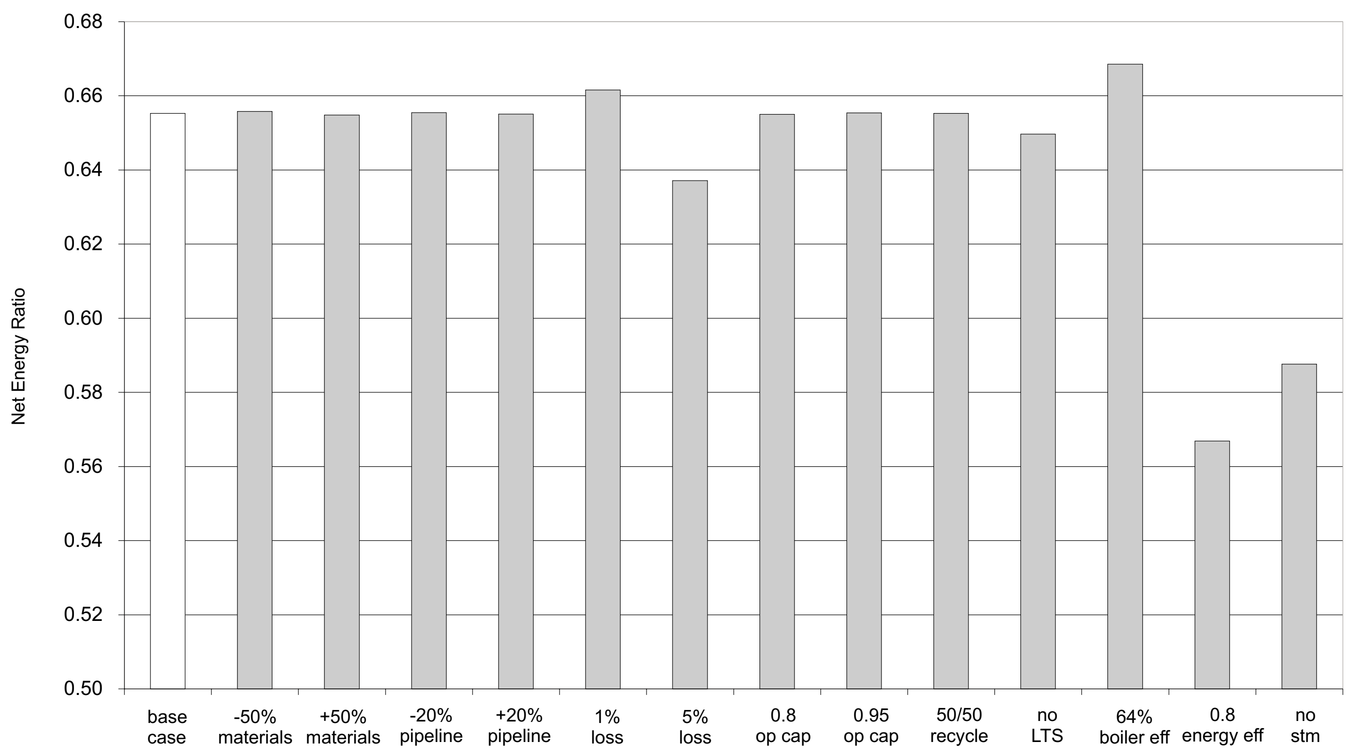
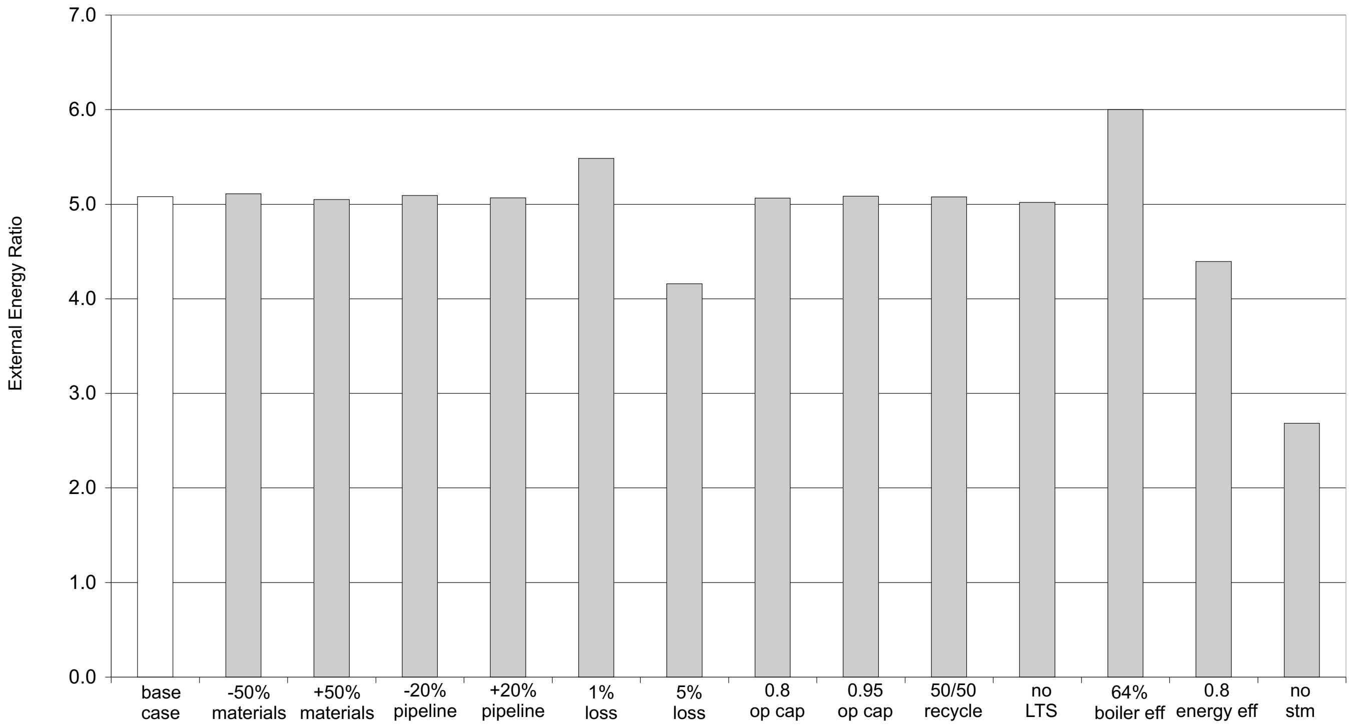


Figure 8: Sensitivity Results for External Energy Ratio



8.0 Impact Assessment

Life cycle impact assessment is a means of examining and interpreting the inventory data from an environmental perspective. There are several options for analyzing the system's impact on the environment and human health. To meet the needs of this study, categorization and less-is-better approaches have been taken. See SETAC (1997, 1998) for additional details about the different methods available for conducting impact assessments. Table 15 summarizes the stressor categories and main stressors from the natural gas steam reforming, hydrogen production system. A discussion of these stressor categories as well as information about the known effects of these stressors can be found in Spath and Mann (1999).

Table 15: Impacts Associated with Stressor Categories

Stressor categories		Stressors	Major impact category H = human health E = ecological health	Area impacted L= local (county) R = regional (state) G = global
Major	Minor			
Ozone depletion compounds		NO	H, E	R, G
Climate change	Greenhouse gases	CO_2, CH_4, N_2O, CO and NO_x (indirectly), water vapor	H, E	R, G
	Particulates		H, E	L, R
Contributors to smog	Photochemical	NO_x, VOCs	H, E	L, R
Acidification precursors		SO_2, NO_x, CO_2	H, E	L, R
Contributors to corrosion		SO_2, H_2S, H_2O	E	L
Other stressors with toxic effects		NMHCs, benzene	H, E	L
Resource depletion		Fossil fuels, water, minerals, and ores	E	R, G
Solid waste		Catalysts, coal ash (indirectly), flue gas clean up waste (indirectly)	H, E	L, R

9.0 Improvement Opportunities

The component of life cycle assessment known as improvement, is used to identify opportunities for reducing the environmental impact of a system. From the sensitivity analysis, it is evident that the hydrogen plant energy efficiency has the largest effect on the system stressors (resources, emissions, waste, and energy use) and thus this variable has the largest environmental impact. Because SMR and shift conversion are conventional technologies where improvements have been made in the past, significant increases in yields through changes in furnace/reactor designs or catalyst types are not expected. However, it is important to note that the hydrogen production plant should be operated as efficiently as possible to minimize the environmental burden of the system.

Reducing the natural gas losses is an opportunity for improvement and this would improve the GWP of the system. The base case analysis shows that 11% of the GWP is a result of methane emissions and 76 wt% of the total system methane comes from natural gas lost during production and distribution. If the losses were reduced from 1.4% to 0.5%, methane would account for 6% of the GWP instead of 11%. Reducing the natural gas losses would also improve the energy balance of the system. Depending on the composition of the natural gas, approximately 48,400 J of energy are lost per gram of natural gas that leaks to the atmosphere (LHV basis). For the base case, 2.7 MJ are lost per kg of H_2 produced and this would be reduced to 0.5 MJ/kg of H_2 if the natural gas losses were only 0.5%. As discussed in section 5.0, the Natural Gas STAR Program is an industry consortium working to reduce methane emissions from natural gas production and distribution.

10.0 Conclusions

Although hydrogen is generally considered to be a clean fuel, it is important to recognize that its production may result in environmental consequences. Examining the resource consumption, energy requirements, and emissions from a life cycle point of view gives a complete picture of the environmental burdens associated with hydrogen production via steam methane reforming. 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 99 wt% of the total air emissions and 89% of the system GWP. Another air emission that effects the GWP of the system is CH_4, which primarily comes from the natural gas lost to the atmosphere during production and distribution. The energy balance of the system shows that for every 0.66 MJ of hydrogen produced, 1 MJ of fossil energy must be consumed (LHV basis). From both an environmental and economic standpoint, it is import to increase the energy efficiencies and ratios of any process. This in turn will lead to reduced resources, emissions, wastes, and energy consumption. Future work will involve comparing this study with hydrogen production via other routes such as biomass, wind, and photovoltaics.

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13. ABSTRACT *(Maximum 200 words)* A life cycle assessment of hydrogen production via natural gas steam reforming was performed to examine the net emissions of greenhouse gases as well as other major environmental consequences. LCA is a systematic analytical method that helps identify and evaluate the environmental impacts of a specific process or competing processes.

February 2001 Revision Notes: Notes regarding changes from the August 2000 published version of this report.
Pages 7, 10, and 15 contain updated information.

November 2000 Revision Notes: Notes regarding changes from the August 2000 published version of this report.
A reduction was made in the amount of natural gas losses. This changed several of the numbers and percentages given throughout the report. However, most of the values varied by a small amount and the conclusions remain the same. The Executive Summary, pages 8–21 and pages 23–24 contain updated information.

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