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Conceptual Design of Optimized Fossil Energy Systems with Capture and Sequestration of Carbon Dioxide

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ABSTRACT

In this semi-annual progress report, we describe research results from an ongoing study of fossil hydrogen energy systems with CO_2 sequestration. This work was performed under NETL Award No. DE-FC26-02NT41623, during the six-month period September 2002 through March 2003.

The primary objective of the study is to better understand system design issues and economics for a large-scale fossil energy system co-producing H_2 and electricity with CO_2 sequestration. This is accomplished by developing analytic and simulation methods for studying the entire system in an integrated way. We examine the relationships among the different parts of a hydrogen energy system, and attempt to identify which variables are the most important in determining both the disposal cost of CO_2 and the delivered cost of H_2.

A second objective is to examine possible transition strategies from today's energy system toward one based on fossil-derived H_2 and electricity with CO_2 sequestration. We are carrying out a geographically specific case study of development of a fossil H_2 system with CO_2 sequestration, for the Midwestern United States, where there is presently substantial coal conversion capacity in place, coal resources are plentiful and potential sequestration sites in deep saline aquifers are widespread.

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EXECUTIVE SUMMARY

In this semi-annual progress report, we describe research results from an ongoing study of fossil hydrogen energy systems with CO_2 sequestration. This work was performed during the first six months (September 2002-March 2003) of a one-year project under NETL Award No. DE-FC26-02NT41623.

The primary objective of the study is to better understand system design issues and economics for a large-scale fossil energy system co-producing hydrogen (H_2) and electricity with carbon dioxide (CO_2) sequestration. This is accomplished by developing new analytic and simulation tools for studying the entire system in an integrated way. We examine the relationships among the various parts of a fossil hydrogen energy system, and attempt to identify which variables are the most important in determining both the disposal cost of CO_2 and the delivered cost of H_2.

A second objective is to examine possible transition strategies from today's energy system toward one based on fossil-derived H_2 and electricity with CO_2 sequestration. We plan to carry out a geographically specific case study of development of a fossil H_2 system with CO_2 sequestration, for the Midwestern United States, where there is presently substantial coal conversion capacity in place, coal resources are plentiful and potential sequestration sites in deep saline aquifers are widespread.

We consider fossil energy complexes producing both H_2 and electricity from either natural gas or coal, with sequestration of CO_2 in geological formations such as deep saline aquifers. The design and economics of the system depend on a number of parameters that determine the cost and performance of the system "components", as a function of scale and geography (components include: the fossil energy complex, H_2 pipelines and refueling stations, CO_2 pipelines, CO_2 sequestration sites, and H_2 energy demand centers). If we know the location, size, cost and performance characteristics of the components, designing the system can be posed as a problem of cost minimization. The goal is to minimize the delivered H_2 cost with CO_2 disposal by co-optimizing the design of the fossil energy conversion facility and the CO_2 disposal and H_2 distribution networks. Research to perform this cost minimization has two parts: 1) implement technical and economic models for each "component" in the system, and 2) develop optimization algorithms to size various the system components and connect them via pipelines into the lowest cost network serving a particular energy demand. Finally, to study transition issues, we use these system models to carry out a case study of developing a large-scale fossil energy system in the Midwestern United States.

Three tasks are ongoing. Most of the work described in this report was performed under Tasks 1 and 2. In future reports, we will present more complete results from Task 3.

Task 1.0 Implement Technical and Economic Models of the System Components

Here we utilize data and component models of fossil energy complexes with H_2 production, and CO_2 sequestration already developed or undergoing development as part of the ongoing Carbon Mitigation Initiative (CMI). (Begun in 2001, the Carbon Mitigation Initiative is a ten-year $15-20 million dollar joint project of Princeton University, BP and Ford Motor

Company to find solutions to global warming and climate change.) Additional models for H_2 distribution systems and refueling stations are being adapted from the principal investigator's previous studies of H_2 infrastructure for the US Department of Energy Hydrogen R&D Program (Ogden 1998, Ogden 1999a, Ogden 1999b), and those of other researchers (Mintz et al. 2003, Amos 1998, Thomas et al. 1998).

Task 2.0. Integrated Studies of the Entire System to Find the Lowest Cost Network

As a first step, we developed a simple analytical model linking the components of the system. We consider single fossil energy complex connected to a single CO_2 sequestration site and a single H_2 demand center. We developed "cost functions" for the CO_2 disposal cost and the delivered H_2 cost with explicit dependence on the many input parameters described above (e.g. size of demand, fossil energy complex process design, aquifer physical characteristics, distances, pressures etc.). Analytic sensitivity studies of this "simple system" are used to provide us with insights on which parameters are most important in determining costs.

To study more complex and realistic systems involving multiple energy complexes, H_2 demand centers, and sequestration sites, we will be exploring use mathematical programming methods to find the lowest cost system design. From our system modeling, we seek to distill "rules for thumb" for developing H_2 and CO_2 infrastructures.

Task 3.0 Case Study of Transition to a Fossil Energy System with CO_2 Sequestration

In this task, we plan to explore transition strategies: how H_2 and CO_2 infrastructures might develop in time, in the context of a geographically specific regional case study. We focus on the Midwestern United States, a region where coal is widely used today in coal-fired power plants, and good sites for CO_2 sequestration are available. The goal is to identify attractive transition strategies toward a regional hydrogen/electricity energy system in the Midwest with near zero emissions of CO_2 and air pollutants to the atmosphere.

To better visualize our results, we plan use a geographic information system (GIS) format to show the location of H_2 demand, fossil energy complexes, coal resources, existing infrastructure (including rights of way), CO_2 sequestration sites and the optimal CO_2 and H_2 pipeline networks. As an initial step, a survey of relevant GIS data sets was conducted, and initial work was begun on building a database.

INTRODUCTION

In this progress report, we present initial results from an ongoing assessment of fossil hydrogen energy systems with CO_2 sequestration. This research was performed from September 2002-March 2003, during the first six months of a contract under NETL Award No. DE-FC26-02NT41623.

Background and Motivation

Production of hydrogen from fossil sources with capture and sequestration of CO_2 offers a route toward near-zero emissions in production and use of fuels. Implementing such an energy system on a large scale would require building two new infrastructures: one for producing and delivering H_2 to users (such as vehicles) and one for transmitting CO_2 to disposal sites and securely sequestering it.

In Figure 1, we show a fossil hydrogen energy system with CO_2 sequestration. A fossil feedstock (natural gas or coal) is input to a fossil energy complex producing hydrogen and electricity. CO_2 is captured, compressed to supercritical pressures for pipeline transport to a sequestration site, and injected into an aquifer or other underground geological formation. Hydrogen is delivered to users via a pipeline distribution system that includes compression and storage at the hydrogen production plant, pipelines (possibly with booster compressors) and hydrogen refueling stations. The design and economics of a fossil H_2 energy system with CO_2 sequestration depend on a host of factors, many of which are regionally specific and change over time. (Variable considered in this study are shown in Figure 1 in italics.) These include:

- The size, type, location, time variation and geographic density of the H_2 demands.
- Cost and performance of component technologies making up the system. Key components are: the fossil energy conversion plant [design variables include the scale, feedstock: (coal vs. natural gas), process design, electricity co-production, separation technology, pressures and purity of H_2 and CO_2 products, sulfur removal options including co-sequestration of sulfur compounds and CO_2, location (distance from demand centers and sequestration sites)], H_2 and CO_2 pipelines and H_2 refueling stations.
- The location and characteristics of the CO_2 sequestration sites (storage capacity, permeability, reservoir thickness),
- Cost, location and availability of primary resources for H_2 production.
- Location of existing energy infrastructure and rights of way (that could be used for siting hydrogen transmission pipelines).

For simplicity, in Figure 1, we have shown a single fossil energy complex, serving a single demand, and one CO2 sequestration site. However, a future fossil hydrogen system could be more complex, linking multiple H_2 demand centers (cities), fossil energy complexes and sites for CO_2 sequestration (Figure 2).

Several detailed technical and economic studies have been carried out for various parts of the system, including CO_2 capture from electric power plants (Hendriks 1994; Foster Wheeler 1998; Simbeck 1999), or H_2 plants (Foster Wheeler 1996; Doctor et al. 1999; Spath and Amos 1999; Kreutz et al. 2002), CO_2 transmission (Skovholt 1993) and storage (Holloway 1996), and H_2 infrastructure (Directed Technologies et al. 1997, Ogden 1999; Thomas et al. 1998, Mintz et al 2002). However, relatively little work has been done assessing complete fossil hydrogen systems with CO2 sequestration in an integrated way. An integrated viewpoint is important for understanding the design and economics of these systems. For example, the scale of the fossil hydrogen plant, can have a large impact on the design and cost of both the hydrogen distribution system, and the system for transporting and sequestering CO_2.

Scope of this Study

The primary objective of this study is to better understand total system design issues and economics for a large-scale fossil energy system co-producing hydrogen (H_2) and electricity with CO_2 sequestration. We consider fossil energy complexes producing both H_2 and electricity from either natural gas or coal, with sequestration of CO_2 in geological formations such as deep saline aquifers. We apply various analytic and simulation methods to study the entire system in an integrated way. We attempt to identify which variables are the most important in determining both the disposal cost of CO_2 and the delivered cost of H_2. We examine the relationships among the system components (e.g. fossil energy complexes, H_2 and CO_2 pipelines, H_2 demand centers, and CO_2 sequestration sites), and apply new simulation tools to studying these systems, and optimizing their design.

A second objective is to examine possible transition strategies from today's energy system toward one based on fossil-derived H_2 and electricity with CO_2 sequestration. We focus on understanding how H_2 and CO_2 infrastructures might evolve over time to meet a growing H_2 demand under different regional conditions. If we know the location, size, cost and performance characteristics of the system components, designing the system can be posed as a problem of cost minimization. The goal is to minimize the delivered H_2 cost with CO_2 disposal by co-optimizing the design of the fossil energy conversion facility and the CO_2 and H_2 pipeline networks. Research to perform this cost minimization has two parts: 1) implement technical and economic models for each component in the system (Task 1), and 2) explore use of optimization algorithms to size various the system components and connect them via pipelines into the lowest cost network serving a particular energy demand (Task 2). Techniques for studying regional H_2 and CO_2 infrastructure development and transition strategies are described, based on use of Geographic Information System (GIS) data and network optimization techniques.

In future work under this contract, we plan to carry out a case study of development of a large scale fossil H_2 system with CO_2 sequestration, for the Midwestern United States, where there is presently substantial coal conversion capacity in place, coal resources are plentiful and potential sequestration sites in deep saline aquifers are widespread (Task 3).

Three tasks are ongoing. (Results are given for each task in the "Results and Discussion" section below.) Most of the work described in this report was performed under Tasks 1 and 2. In future reports, we will present results from Task 3.

Task 1.0 Implement Technical and Economic Models of the System Components

Before developing a total system model, we need to develop technical/economic models for the various parts (or components) of the system. He performance and cost of each "component" of the system is characterized as a function of scale and other relevant parameters. In this Task, we utilize data and models of fossil energy complexes with H_2 production, and CO_2 sequestration developed as part of the ongoing Carbon Mitigation Initiative (CMI). (Begun in 2001, the Carbon Mitigation Initiative is a ten-year $15-20 million dollar joint project of Princeton University, BP and Ford Motor Company to find solutions to global warming and climate change.) Additional models for H_2 distribution systems and refueling stations are being adapted from the principal investigator's previous studies of H_2 infrastructure for the US Department of Energy Hydrogen R&D Program (Ogden 1998, Ogden 1999a, Ogden 1999b), and those of other researchers (Mintz et al. 2003, Amos 1999, Thomas et al. 1998).

Task 2.0. Integrated Studies of the Entire System to Find the Lowest Cost Network

As a first step, we developed a simple analytical model linking the components of the system. We consider a single fossil energy complex connected to a single CO_2 sequestration site and a single H_2 demand center (see Figure 1). For specificity, we chose a base case hydrogen plant size of 1000 MWth hydrogen output (equivalent to about 600 tonnes H2 per day or 252 million standard cubic feet – see Appendix A for conversion factors). We developed "cost functions" for the CO_2 disposal cost and the delivered H_2 cost with explicit dependence on the many input parameters described above (e.g. size of demand, fossil energy complex process design, aquifer physical characteristics, distances, pressures etc.). Analytic sensitivity studies of this "simple system" are used to provide us with insights on which parameters are most important in determining costs.

To study more complex and realistic systems involving multiple energy complexes, H_2 demand centers, and sequestration sites, we are exploring use mathematical programming methods to find the lowest cost system design. This work will be described in future reports. From our system modeling, we seek to distill "rules for thumb" for developing H_2 and CO_2 infrastructures.

Task 3.0 Case Study of Transition to a Fossil Energy System with CO_2 Sequestration

In this task, we plan to explore transition strategies: how H_2 and CO_2 infrastructures might develop in time, in the context of a geographically specific regional case study. We focus on the Midwestern United States, a region where coal is widely used today in coal-fired power plants, and good sites for CO_2 sequestration are available. We consider how fossil energy systems might develop over time to meet an evolving energy demand. The goal is to identify attractive transition strategies toward a regional hydrogen/electricity energy system in the Midwest with near zero emissions of CO_2 and air pollutants to the atmosphere.

To better visualize our results, we plan to use a geographic information system (GIS) format to show the location of H_2 demand, fossil energy complexes, coal resources, existing infrastructure (including rights of way), CO_2 sequestration sites and the optimal CO_2 and H_2 pipeline networks. As a first step, a survey of relevant GIS data sets was conducted, and initial work was begun on building a database. Results for Task 3 will be presented in future technical reports.

RESULTS AND DISCUSSION

BASE CASE ASSUMPTIONS

Before presenting results from Tasks 1-3, we outline the "base case" assumptions used in our analysis. In estimating levelized costs of hydrogen and CO_2, we use the economic assumptions in Table 1.

Table 1. Economic assumptions

CRF = annual capital charge rate	0.15
Annual non-fuel O&M as a fraction of installed capital cost	0.04
Capacity factor	80%
Natural Gas Price ($/GJ) HHV	3.75
Coal Price ($/GJ) HHV	0.95
Electricity Price ($/kWhe)	0.036

Feedstock costs are USDOE projections for 2020 costs to electric utilities: $3.75/GJ for natural gas and $0.95/GJ for coal (US DOE EIA 2002). The electricity price of $0.036/kWh is based on electricity produced in a natural gas turbine combined cycle, assuming a natural gas price of $3.75/GJ (Williams 2002.) Costs are in constant 2001 US dollars.

In Table 2, we summarize the assumptions and range of parameters considered for fossil hydrogen systems with CO_2 sequestration. We consider energy systems producing H_2 and electricity from fossil feedstocks (natural gas or coal), with capture of CO_2, compression to 15 MPa for pipeline transmission as a supercritical fluid, and injection into an underground reservoir. H_2 is compressed to 6.8 MPa (1000 psi) for on-site storage, pipeline transmission and local distribution to H_2 vehicles. We consider H_2 plants with an output capacity of 250-1000 MW of H_2, higher heating value basis (150-600 tonnes H_2/day). At an assumed 80% capacity factor, annual H_2 production is 6.3-25.2 million GJ (45,000-178,000 tonnes)—enough to fuel 0.35-1.4 million H_2 fuel cell cars having a fuel economy of 2.9 liters gasoline per 100 km (82 miles per gallon) and driven 17,700 km (11,000 miles) per year (the US average). Hydrogen refueling stations are assumed to dispense 2500 kg of hydrogen per day or about 1 million standard cubic feet per day. This would be enough to support a fleet of about 6000 cars.

In Table 3, we compare hydrogen demands with hydrogen supply options. (Large demands and large supplies are shown in boldface type. For large fossil supplies, we indicate the amount of CO2 that could be captured during hydrogen production.) Large

Table 2. Parameter Ranges Considered in this Study for Fossil Hydrogen Systems with CO2 Sequestration

Hydrogen Production Capacity Range at Fossil Energy Complex	250 – 1000 MW H_2 (HHV) (150-600 tonnes H_2/day) (62-252 million scf H_2/d)
Associated CO_2 production Range	
Natural gas -> H2 Plant, 85% of CO_2 captured	51-204 tonne CO_2/h
Coal -> H2 Plant, 90% of CO_2 captured	101-406 tonne CO_2/h
H_2 Plant Capacity Factor	80%
H_2 Buffer Storage Capacity at Production Site	1/2 day's production
H_2 Local Distribution Pipeline	
H_2 Inlet Pressure	6.8 MPa (1000 psi)
H_2 Outlet Pressure (at refueling station)	>1.4 MPa (200 psi)
Pipeline capital cost ($/m)	$155-622/m ($0.25-1 million/mile)
Hydrogen Demand	
1 H2 Fuel Cell Car (82 mpgge, 11,000 mi/y)	0.375 kg/day
1 H2 Bus (7 mpgge, 50,000 mi/yr)	20 kg/day
H_2 Refueling Stations	
Hydrogen dispensed per day	2.4 tonne/day (1 million scf/d)
Dispensing Pressure to Vehicle	6000 psia
Onboard H_2 Storage Pressure	34.5 MPa (5000 psia)
CO_2 Pipeline	
CO_2 Pipeline flow rate (range)	1,000-10,000 tonnes/day
Inlet Pressure (at H_2 Plant)	15 MPa
Outlet Pressure (at Sequestration Site)	10 MPa
Pipeline Length (range)	10-1000 km
CO_2 Sequestration Site	
Well depth	2 km
Permeability (milliDarcy)	> 50 milliDarcy
Reservoir Layer Thickness	50 m
Maximum flow rate per well	2500 tonnes/day/well

Table 3. Hydrogen Supply and Demand

H_2 Demands	***kg H_2/day***
1 H_2 FC car (82 mpg, 11,000 mi/y)	0.375
1 H_2 FC Bus	20

(7 mpge, 50,000 mi/y)				
100-1000 H_2 FC car fleet cars (82 mpg, 17,000 mi/y)	58-580			
100 –1000 FC Buses	2000-20,000			
100,000 cars (~1% of cars in LA)	**37,500**			
1 million cars (~10% of cars in LA)	**375,000**			
10 million cars (~100% cars in LA)	**3,750,000**			
H_2 Supplies	***kg H_2/day***	***Size of H_2 FC car fleet supported***	***Size of H_2 FC Bus fleet***	***CO2 Captured from Large Fossil H2 Plants (tonne/d)***
Compressed H_2 gas truck (1/day)	420	1120	21	n.a
Liquid H2 truck (1/day)	3600	9600	180	n.a
Onsite electrolyzer	2.4-2400	6.4-6400	0.12-120	n.a.
Onsite steam methane reformer (SMR)	240-4800	640-12,800	12-240	n.a
Industrial scale steam methane reformer	**48,000-480,000**	**128,000-1,280,000**	**2400-24,000**	**400-4000**
Coal gasifier H_2 plant w/CO_2 seq.	**150,000-600,000**	**400,000-1,600,00**	**7500-30,000**	**2500-10,000**
H_2 from 10% of NG Flow into LA	**1,700,000**	**4,533,333**	**85,000**	**15,000**
H_2 from 1000 MW off-peak power	**240,000**	**640,000**	**12,000**	**n.a**

fossil energy complexes with CO_2 sequestration are well matched to large demands: hundreds of thousands of hydrogen vehicles could be served by a single fossil hydrogen plant with CO_2 sequestration. In the early stages of a hydrogen economy (when there are relatively few hydrogen vehicles, it is likely that smaller scale hydrogen delivery options would be used to bring hydrogen to vehicles, including truck delivery of hydrogen or onsite production of hydrogen via small scale steam reforming or electrolysis.

RESULTS FOR TASK 1.0. IMPLEMENT TECHNICAL AND ECONOMIC MODELS OF THE SYSTEM COMPONENTS

In this section we describe models of various parts of a fossil hydrogen system with CO2 sequestration. These include:

- The fossil energy complex for producing hydrogen and electricity from natural gas or coal
- CO2 compression and pipeline transport
- CO2 injection into underground geological formations
- Hydrogen demand for vehicles
- Hydrogen fuel delivery infrastructure (including hydrogen compression, storage, pipeline transmission and refueling stations)

We utilize data and component models of fossil energy complexes with H_2 production, and CO_2 sequestration already developed or undergoing development as part of the ongoing Carbon Mitigation Initiative (CMI) project at Princeton University. Additional models for H_2 distribution systems and refueling stations are being adapted from the principal investigator's previous studies of H_2 infrastructure for the US Department of Energy Hydrogen R&D Program (Ogden 1998, Ogden 1999a, Ogden 1999b), and those of other researchers (Mintz et al. 2003, Amos 1999, Thomas et al. 1998).

Details on the models for various parts of the system are given in Appendices B-E.

Task 1.1. Modeling the Fossil Energy Complex

In this section, we describe simplified models of fossil hydrogen production plants with CO2 capture. We consider hydrogen production from natural gas and from coal.

In the fossil energy complex, a synthetic gas (or syngas) is produced via gasification of coal or steam reforming of methane. The syngas undergoes a water gas shift reaction to increase the hydrogen content. CO_2 is removed from the syngas using a separation system (such as an amine scrubber, a physical adsorption system like Selexol or a pressure swing adsorption system or PSA) and is available at near atmospheric pressure. CO_2 is then compressed from capture pressure to a supercritical state and pumped to pipeline transmission pressures of 15-20 MPa (150-200 bar). In some cases, electricity is co-produced with hydrogen. Simplified diagrams of the process from producing hydrogen from natural gas and coal shown in Figures 3 and 4.

The term "CO_2 capture" generally refers to CO_2 separation and compression prior to pipeline transport to a sequestration site. In this report, we disaggregated the costs of CO_2 separation as distinct from those of CO_2 compression. This allows us to vary the parameters controlling compression costs (such as CO_2 outlet pressure and electricity cost) separately from the plant design, to examine the impact of CO_2 outlet pressure on cost.

As a basis for modeling natural gas-based hydrogen plants, we use a recent study by Foster Wheeler (1996) and data from Air Products and Chemicals (Ogden 1999). As part of the CMI, researchers at Princeton have developed ASPEN-plus process and cost models for a variety of coal-based systems co-producing H_2 and electricity with CO_2

capture (Kreutz, Williams, Socolow and Chiesa 2002), that include alternative options for sulfur removal and disposal. We use the results of these detailed process design studies to produce a simplified model for the cost and performance of fossil H_2 plants as a function of scale, feedstock and process design.

Hydrogen Production from Natural Gas

For natural gas steam methane reforming plants, we use cost and performance estimates from a recent study by Foster Wheeler (Foster Wheeler 1996). Hydrogen is produced at 60 bar output pressure, at the rate of 1000 MWth on a higher heating value basis (this is equivalent to 600 tonnes H2 per day or 252 million standard cubic feet per day). Two cases are shown: one with CO_2 vented and one with capture of 85% of the CO_2. The CO_2 is compressed to 112 bar. Capital costs for these plants are given in Table 4.

From the capital costs in Table 4, the levelized cost for hydrogen production with and without CO_2 separation can be estimated, given the natural gas price, other operation and maintenance costs, the capacity factor and the capital recovery factor (CRF) (see Table 1). The levelized cost of hydrogen production from natural gas with and without CO_2 sequestration is shown in Table 5. CO2 sequestration adds about 25% to the hydrogen production cost.

Another estimate of the cost of CO_2 separation during hydrogen production is based on data from engineers at Air Products and Chemicals (Ogden 1999) for a vacuum swing adsorption (VSA) CO_2 capture system (see Table 6). This type of system could be added as a retrofit to capture CO_2 at an existing steam methane reformer plant. The cost of CO_2 separation (not including compression) is estimated to be about \$0.36-0.38/GJ H_2 on a HHV basis, or about \$13.0-13.7/tonne CO_2. (This is based on capture of about

Table 4. Cost and Performance of Natural Gas Based Hydrogen Production Plants w/ and w/o CO_2 Capture (Foster Wheeler 1996)

	CO_2 vented	**CO_2 captured**
Hydrogen Production MWth (at 60 bar output pressure)	1000	1000
First law efficiency HHV basis	81%	78%
CO_2 emission rate (kgC/GJ H_2)	17.56	2.74
CO_2 Sequestration Rate (tonne/h)	0	204
Capital Investment (million $)		
Reformer	48.65	67.90
Purification	23.65	58.08
CO_2 Compression	0	35.67 (for an estimated CO_2 compressor power of 18.6 MWe)
Other	123.95	174.67
Subtotal	**196.25**	**336.32**
Subtotal (excluding CO_2 compressor)	196.25	300.65
Added costs		
Engineering, construction management, commissioning, training	9.13	16.94
Catalysts and chemical	8.75	9.00
Clients costs	24.00	28.00
Contingency	23.81	39.03
TOTAL INSTALLED CAPITAL COST (million $)	**261.94**	**429.3**
TOTAL INSTALLED CAPITAL COST (excluding CO_2 compressor)	261.94	384.0 (to get the installed capital cost the subtotal without the CO2 compressor has been scaled using the same ratio as subtotal for the total plant)
Incremental Installed Capital Cost for CO_2 Capture (million $)		167.36
Incremental Installed Capital Cost for CO_2 Capture excluding CO_2 compression (million $)		122.06

Table 5. Levelized cost of hydrogen production from natural gas with and without CO_2 separation and compression

Levelized Cost of H_2 Production with CO_2 separation, excluding CO_2 compression ($/GJ H_2) HHV	**CO_2 vented**	**CO_2 captured**
Capital (excluding CO_2 compression)	1.56	2.28
Natural Gas Feedstock	4.20	4.36
Non-fuel O&M	0.42	0.61
CO2 Compressor Capital and O&M	n.a.	0.34
CO2 Compressor Electricity	n.a	0.27
Total (including CO2 compression)	n.a.	7.86
Total (excluding CO_2 compression)	6.17	7.25
Incremental cost of CO_2 separation and compression	**n.a.**	
$/GJ H2 HHV		1.69
$/tonne CO_2		29.8
Incremental cost of CO_2 separation only (excluding CO2 compression)	**n.a.**	
$/GJ H2 HHV		1.08
$/tonne CO_2		19.0

Table 6. Cost of CO_2 Separation During Hydrogen Production Via Large Scale Retrofit to Steam Methane Reforming Plant

Hydrogen Production	80 million scf/day 193 tonnes/day 27,440 GJ/day HHV
CO_2 Production	850 ton/day (771 tonnes/day) 0.18 scf CO2/scf H2 3.99 kg CO2/kg H2
CO_2 Purity	95%
CO_2 pressure	1 atm
Power required for VSA Compressor	3400 kW
Equipment Cost of PSA only	$4-4.5 million
Equipment Cost of VSA only, including compressor	$6-6.6 million
Added factor for freight, taxes, installation	15%
Owner's costs and engineering	25%
Total installed capital cost for PSA only (no CO_2 recovery)[a]	$5.6-6.3 million
Total installed capital cost for PSA + VSA (CO_2 recovery)	$14-15.5 million
Incremental installed capital cost for CO_2 recovery	$8.4-9.2 million
Incremental Levelized Hydrogen Production Cost for CO_2 Separation[b]	
Incremental Capital Cost for VSA	$0.16-0.17/GJ HHV H2
Incremental Non-fuel O&M for VSA	$0.04-0.05/GJ HHV H2
Cost for VSA Compressor Power @ 5.6 cents/kWh	$0.17/GJ HHV
Total Incremental Cost for CO_2 Separation in VSA	$0.37-0.38/GJ HHV $13.0-13.7/tonne CO2

Source: Bob Moore, Air Products and Chemicals. Inc., private communications, May 1997.
The total capital cost was obtained by multiplying the equipment cost by 1.40 to account for taxes, freight, installation, owner's costs and engineering.
The levelized cost is found assuming a capital recovery factor of 15%, annual non-fuel O&M costs of 4%, and an 80% capacity factor.

56% of the carbon input in the natural gas feedstock or 28 kg CO_2 captured/GJ H_2 HHV. Electricity for the vacuum swing adsorption system accounts for about 45% of the cost and capital and non-electricity O&M about 55%). CO_2 is available at 0.1 MPa, and ambient temperature. The cost of CO_2 separation is less than that with the Foster-

Wheeler system, but a substantially lower fraction of the carbon is captured (56% versus 85%).

Hydrogen and Electricity from Coal Gasification

Kreutz, Chiesa and Williams (2002) have modeled the performance and economics of systems for co-producing hydrogen and electricity from gasified coal, with separation and capture of 85% of the CO_2 emissions. (A simplified process flow diagram for the system is shown in Figure 4.) A variety of cases were considered with and without CO_2 capture, varying the gasifier pressure and the treatment of sulfur (see Table 7).

Table 7. Cases Considered for Hydrogen and Electricity Production from Coal

CASE	Gasifier Pressure	Sulfur removal	Sequestration
Hi P, No CO_2 Seq	120 bar	Yes	No
Hi P, CO_2 Seq	120 bar	Yes	CO_2 only
Hi P, CO_2 + H_2S Co-Seq	120 bar	No	CO_2 + H_2S
Lo P, No CO_2 Seq	70 bar	Yes	No
Lo P, CO_2 Seq	70 bar	Yes	CO_2 only
Lo P, CO_2 + H_2S Co-Seq	70 bar	No	CO_2 + H_2S

For each case in Table 7, the sizes, capital costs and O&M costs of the various fossil energy plant components were estimated, along with the energy consumption, hydrogen and electricity production, and carbon emissions (Kreutz 2002). From these studies, we can examine the impact of plant design on the economics of H_2 production and CO_2 capture (Table 8). This is complicated, because the plant design changes in several ways, depending on whether CO_2 is captured, and whether sulfur compounds are separated.

With CO_2 capture (versus CO_2 venting), additional electricity can be co-produced at the plant, for a given hydrogen output. Although some of this electricity is used in the plant for CO2 compression, there is still excess electricity produced, above the plant demands. A credit is claimed for by-product electricity.

When co-sequestration of H_2S and CO_2 is done, sulfur removal equipment is not needed, so there are savings on capital costs, compared to a case with sulfur removal and CO_2 separation. As compared to the case where CO_2 is vented, the capital cost of the fossil energy complex is almost unchanged when H_2S is co-sequestered with CO_2, when CO_2 compressor costs are included. The savings on sulfur removal equipment approximately balance the extra costs for separating and compressing CO_2.

For a case with sulfur removal and CO_2 capture, the plant capital costs and levelized cost of hydrogen are higher than the case where CO_2 is vented.

Figure 5 shows the levelized cost of hydrogen production (in \$/GJ) from natural gas and coal with and without CO_2 capture. We assume that each plant has a hydrogen output of 1000 MWth. Each component contributing to the cost is shown (e.g. capital costs, feedstock costs, O&M and by-product credits). For coal plants, by-product electricity is a factor in determining the hydrogen cost. (We show a by-product credit for the total amount of electricity produced. In cases with CO_2 compression, some of this credit is applied to the cost of compressor power, so the net power exported is the by-product electricity minus the compressor electricity.) The cost of hydrogen from natural gas is increased by about 25% with CO2 capture. The cost of hydrogen from coal is about the same with co-sequestration of CO2 and H2S.

For our assumptions, the cost of hydrogen production from coal is slightly less than for hydrogen from natural gas, with or without CO2 sequestration.

Sensitivity to the Electricity Cost

The cost of hydrogen from coal is sensitive to the assumed cost of electricity. For the cases shown in Figure 5, electricity is valued at 3.6 cents/kWh. If electricity is worth more than this, the by-product credit is increased, and the cost of hydrogen from coal is reduced by about \$0.2/GJ for each added cent per kWh of electricity cost.

Effects of Scale on the Cost of H2 Production and CO2 Separation in Fossil Energy Complexes

The cost of hydrogen production and CO2 separation depend on the plant size. We assume that process equipment capital costs depend on size according to a power law,

$$\text{Cost (C)} = \text{Cost (Co)} \times (\text{C/Co})^{\alpha}$$

where Co is a reference capacity, Cost(Co) is the cost at capacity Co, C is the actual capacity, and the power α is typically in the range 0.3-1, depending on the technology.

For hydrogen from coal, Kreutz (2002) estimated that the capital cost of the plant scales approximately as $\alpha = 0.828$, where Co = 863 MWth H2 output. For hydrogen from natural gas, we assume that for capital equipment $\alpha = 0.7$, except for CO2 compressors, which are assumed to scale as $\alpha = 0.3$ (see section on CO2 compressors below and in Appendix C).

The cost contribution of capital to the levelized hydrogen scales as

$$PH_2\text{ (C)} = PH_2\text{ (Co)} \times (\text{C/Co})^{\alpha-1}$$

In Table 9, the cost contributions of capital and non-fuel O&M to the levelized hydrogen cost scale as the 1-α power, while the other contributions (for compressor power, coal feedstock) are unchanged with scale. The levelized cost of hydrogen can be calculated as a function of plant size for coal-based and natural gas based hydrogen plants (see Tables 9 and 10). The cost of hydrogen increases at smaller plant sizes. For example, for a natural gas based hydrogen plant with CO2 capture, the cost of hydrogen increases from $7.86/GJ to $9.91/GJ, about 27%, as the plant size decreases from 1000 to 250 MWth hydrogen output.

In Figure 6, we plot the levelized cost of hydrogen production from natural gas and coal as a function of plant size, assuming the CO2 is vented. In Figure 6, we show how the cost of H_2 production with CO_2 separation varies with plant size for natural gas based and coal based hydrogen plants. CO_2 capture is costlier in the natural gas based hydrogen plant than in the coal plant. This is true even though more carbon must be processed in the coal plant, because of the electricity byproduct credit for electricity produced at the coal plant.

Because coal plants are more capital intensive than natural gas plants, the hydrogen cost is slightly more sensitive to scale for coal.

Table 8. Cost and Performance for Hydrogen and Electricity Production from Coal (70 bar gasifier) (Kreutz 2002)

	CO_2 Vented, sulfur removal	CO_2 Capture, sulfur removal	CO_2 capture, co-sequestration of CO_2 and H_2S
H2 Production MWth	1000	1000	1000
Electricity production (net power out) MWe	52.2	30.9	30.9
First law efficiency HHV	0.736	0.705	0.705
CO2 emission rate (kgC/GJ H2 HHV)	35.6	2.61	2.61
CO2 captured (tonne/h)	0	437.4	437.4
Installed Capital Cost of Fossil Energy Complex (million $) = 1.16 x Bare Capital Equipment Cost			
H2 Plant excluding CO_2 compressor	658.6	707.2	612.6
CO2 Compressor	0	51.7 (36.6 MWe)	51.7 (36.6 MWe)
H2 Plant including CO2 Compressor	658.6	758.9	663.4
Incremental plant cost for CO2 capture including CO2 compression	0	100.3	4.8
Incremental plant cost for CO2 separation excluding CO2 compression	0	48.7	-46.0
Levelized Cost of H2 Production ($/GJ HHV)			
Plant capital except CO2 Compressor	3.92	4.20	3.64
Non-fuel O&M	1.04	1.12	0.97
Feedstock cost	1.26	1.32	1.32
CO2 compression capital + O&M		0.39	0.39
CO2 compressor power		0.57	0.57
Electricity credit incl comp pwr	-0.52	-0.675	0.675
Total without CO2 compression	5.70	5.97	5.23
Total with CO2 compression		6.73	6.01
Incremental Cost of CO2 Capture, excluding CO2 compression			
$/GJ H2 (HHV)		0.27	-0.44
$/tonne CO2		2.22	-3.56
Incremental Cost of CO2 Capture, including CO2 compression			
$/GJ H2 (HHV)		1.02	0.31
$/tonne CO2		8.43	2.56

Table 9. Cost of Hydrogen Production from Coal as a Function of Plant Size

	CO_2 Vented, sulfur removal			CO_2 Capture, sulfur removal			CO_2 capture, co-sequestration of CO_2 and H_2S		
H2 Production MWth	1000	500	250	1000	500	250	1000	500	250
CO2 captured (tonne/h)				437.4	218.7	109.4	437.4	218.7	109.4
Levelized Cost of H2 Production ($/GJ HHV)									
Plant capital except CO2 Compressor	3.92	4.41	4.97	4.20	4.74	5.34	3.64	4.10	4.62
Non-fuel O&M	1.04	1.18	1.33	1.12	1.26	1.42	0.97	1.09	1.23
Feedstock cost	1.26	1.26	1.26	1.32	1.32	1.32	1.32	1.32	1.32
CO2 compression capital + O&M				0.39	0.63	1.03	0.39	0.63	1.03
CO2 compressor power				0.37	0.37	0.37	0.37	0.37	0.37
Electricity credit incl comp pwr	-0.52	-0.52	-0.52	-0.68	-0.68	-0.68	-0.68	-0.68	-0.68
Total without CO2 compression	**5.70**	**6.33**	**7.03**	5.97	6.65	7.41	5.26	5.84	6.50
Total with CO2 compression				**6.73**	**7.64**	**8.80**	**6.01**	**6.84**	**7.89**
Incremental Cost of CO2 Capture, excluding CO2 compression									
$/GJ H2 (HHV)				0.27	0.32	0.37	-0.44	-0.48	-0.53
$/tonne CO2				2.22	2.64	3.07	-3.65	-3.98	-4.38
Incremental Cost of CO2 Capture, including CO2 compression									
$/GJ H2 (HHV)				1.02	1.32	1.77	0.31	0.51	0.86
$/tonne CO2				8.43	10.9	14.5	2.56	4.24	7.08

Table 10. Cost of Hydrogen Production from Natural Gas as a Function of Plant Size

	CO_2 Vented			CO_2 Captured		
H2 Production MWth	1000	500	250	1000	500	250
CO2 captured (tonne/h)	0	0	0	204	102	51
Levelized Cost of H2 Production ($/GJ HHV)						
Plant capital except CO2 Compressor	1.56	1.92	2.36	2.28	2.81	3.46
Non-fuel O&M	0.41	0.50	0.62	0.61	0.75	0.92
Feedstock cost	4.20	4.20	4.20	4.36	4.36	4.36
CO2 compressor capital + non-electric O&M				0.34	0.55	0.90
CO2 compressor power				0.27	0.27	0.27
Total without CO2 compression	6.17	6.63	7.19	7.25	7.92	8.74
Total with CO2 compression				7.86	8.74	9.91
Incremental Cost of CO2 Separation only, excluding CO2 compression						
$/GJ H2 (HHV)				1.08	1.29	1.55
$/tonne CO2				19.06	22.81	27.43
Incremental Cost of CO2 Capture, including CO2 separation and compression						
$/GJ H2 (HHV)				1.69	2.11	2.72
$/tonne CO2				29.82	37.32	48.03

Task 1.2.Modeling CO_2 Compression and Pipeline Transport

Once CO2 has been captured at the fossil energy complex, it must be compressed to supercritical pressures and transported by pipeline to a suitable sequestration site.

CO2 Compression

Equations for compressor power requirements and cost models for CO2 compressors are developed in Appendix B. The electric power required for compression of CO2 to supercritical pressures (15 MPa) is modest, perhaps 6% of the total hydrogen power output (in MW thermal, based on the higher heat value of hydrogen). The levelized cost of CO2 compression is plotted in Figures 8 and 9 for various compressor sizes and pressure differences, for CO2 flows from a 1000 MW H2 plant producing 437 tonnes CO2/h (H2 from coal) and 204 tonnes CO2/h (H2 from natural gas). The levelized cost of compression is found to be about $4-6/tonne CO2, for compressor electricity costing 3.6 cents/kwh.

CO2 compression costs show the following sensitivities to varying parameters:

- The cost of electricity dominates the levelized cost of compression. For our base case assumptions, about $3-3.5/tonne CO2 is due to power costs, the remainder to capital costs. The cost of compression is sensitive to the assumed electricity cost.

- Compressor capital costs are sensitive to scale, although power costs per GJ of hydrogen or tonne of CO2 are independent of the compressor power.

- Compression costs are somewhat sensitive to the compressor outlet pressure. This pressure is typically at least 15 MPa, to assure that the CO2 stays above the critical pressure throughout the pipeline. Figures 8 and 9 show the dependence of the levelized cost of compression on the compressor outlet pressure, assuming at inlet pressure of 0.1 MPa. There is a modest incremental cost of about $1/tonne CO2 to increase the outlet pressure from 80 to 150 bar for pipeline transmission.

CO2 Pipeline Transmission

We use a technical/economic model for supercritical CO_2 pipeline transmission developed by the principal investigator under the CMI program. Our model is based on pipeline flow equations developed in (Farris 1983) and (Mohitpour 2000). [Details of CO2 pipeline flow and cost calculations are given in Appendix C.] This model has been benchmarked with existing CO_2 pipeline models in the literature (Farris 1983, Skovholt 1993), and with industry practice through conversations with engineers at BP.

One of the issues in estimating CO2 pipeline costs is the wide variation in published estimates. This is shown in Figure 10, where installed CO2 pipeline costs (in $/m of pipeline length) according to various studies are plotted versus pipeline diameter (Doctor 1999; Skovholt 1993; Holloway 1996; Fisher, Sloan and Mortensen 2002). We have selected a mid-range value for our studies, recognizing that published estimates of capital costs for CO_2 pipelines vary over more than a factor of two above and below the midrange value. The wide variation is probably due to differences in local terrain, construction costs and rights of way, all of which are important variables in determining the actual installed pipeline cost.

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Using a cost function fit to published pipeline data, and inlet and outlet pressure of 15 MPa and 10 MPa, respectively, we find a pipeline capital cost per unit length ($/m), in terms of the flow rate Q and the pipeline length L:

$$\text{Cost }(Q,L) = \$700/\text{m} \times (Q/Qo)^{0.48} \times (L/Lo)^{0.24} \qquad [1]$$

Where Qo = 16,000 tonnes CO2/day and Lo = 100 km.

Figures 11 a and b show the cost of CO2 pipeline transmission as a function of pipeline flow rate and pipeline length.

The levelized cost of pipeline transmission ($/t CO2) scales approximately as

$(\text{CO2 flow rate})^{-0.52} \times (\text{pipeline length})^{1.24}$

For our base case 1000 MW coal and natural gas hydrogen plants, the CO2 flow rates are about 10,000 tonnes/day and 5,000 tonnes/day, respectively. The levelized cost of CO_2 pipeline transmission 100 km is $3.45/t CO_2 for the coal H_2 plant and $5.26/t$CO_2$ for the natural gas H_2 plant. The cost per tonne of CO2 is lower for the coal hydrogen plant than the natural gas hydrogen plant, because of its larger CO2 flow rate. However, the cost per GJ of hydrogen produced is higher for the coal plant, because more CO2 is produced per unit of hydrogen (Figure 11c).

It is assumed that booster compressors are not needed for our base case 100 km pipeline. For pipeline transmission lengths of more than 200 km, booster compressors might be needed, and this could add to costs for CO2 transmission.

Task 1.3. Modeling CO_2 Sequestration sites

At the CO2 sequestration site, CO2 is injected into an underground geological formation such as a deep saline aquifer or depleted hydrocarbon reservoir. A CO2 booster compressor might be needed at the injection well-head depending on the well depth and the aquifer pressure. Several injection wells might be needed, which would be connected via above ground piping. Models for injection rate and capacity of underground geological formations are described based on fundamental reservoir parameters (see Appendix D for details). The injection rate of CO_2 into an underground reservoir depends on the permeability and thickness of the reservoir, the injection pressure, the reservoir pressure, the well depth, and the viscosity of CO_2 at the injection pressure. A practical upper limit on the injection rate per well is taken to be 2500 tonnes per day, limited by pressure drop due to friction in the well at higher flow rates, assuming practical well diameters (Hendriks 1994). Using a standard equation for flow into an injection well (Hendriks 1994), this upper limit implies that for a layer thickness above 50 m and permeabilities above 40 milliDarcy , the flow rate is limited not by the reservoir characteristics, but by the pipe friction flow constraints. For the base case 1000 MW natural gas (coal) to H_2 plant, producing about 5,000 (10,000) tonnes CO_2 per day, 2 (4) wells are needed. The installed capital cost of each well is (Hendriks 1994):

Capital (\$/well) = \$1.56 million x well depth (km) + \$1.25 million.

In our base case, we assume a well depth of 2 km. CO_2 is distributed by surface piping at the injection site from well to well. We require each reservoir to store 20 years of CO_2 production from the H_2 plant. For our base case (reservoir thickness of 50 m), the length of surface piping required at the injection site is found to be 12 (37) km for the natural gas (coal) based H_2 plant. This implies a cost of \$3.2 (9.2) million, based on a piping cost from Equation [1], but assuming that the minimum cost is \$155,000/km (\$250,000/mile) (Ogden 1999). As long as the aquifer characteristics allow such a relatively high injection rate, the cost of injection wells and associated piping is less than \$2/tonne CO_2 [\$0.10(0.26)/GJ(H_2) for H_2 from natural gas(coal).]

The total levelized cost of CO_2 pipeline transmission and storage is shown in Table 11, for hydrogen plants producing 1000 MW of hydrogen per day from natural gas and coal. Per tonne of CO_2, the cost of CO_2 disposal is higher for natural gas, but because the coal plant produces about twice as much CO_2 as the natural gas H_2 plant, the contribution to the levelized cost of H_2 (\$/GJ) is higher for coal. However, the sum of the costs for CO_2 capture (\$1.33/GJ H_2 for natural gas (Williams 2002) and \$0.95/GJ H_2 for coal (Kreutz et al. 2002) and disposal (\$0.39/GJ H_2 for natural gas and \$0.59/GJ H_2 for coal) is about same for natural gas and coal.

Table 11. CO_2 Pipeline Transmission and Storage System for Base Case H2 Plants Producing 1000 MW of hydrogen output from Natural Gas and Coal

	H_2 from natural gas	**H_2 from coal**
CO_2 captured (tonne/h) at full capacity	204	406
CO_2 Disposal System (100 km pipeline, 2 km well depth, injection rate = 2500 t CO_2/day/well)		
CO_2 100 km Pipeline Diameter (m)	0.25	0.34
Number of CO_2 Injection Wells	2	4
Injection Site Piping length (km)	12.2	37
System Capital Cost (million \$)		
CO_2 100 km Pipeline	40.5	55.7
CO_2 Injection Wells	8.8	17.5

CO_2 Injection Site Piping	3.2	9.2
Total CO_2 Pipeline Transmission and Storage System	*52.5*	*82.4*
Levelized Cost of CO_2 Disposal (\$/tCO_2)		
CO_2 100 km Pipeline	5.26	3.45
CO_2 Injection Wells	1.16	1.17
CO_2 Injection Site Piping	0.44	0.61
Total CO_2 Pipeline Transmission and Storage System	*6.87*	*5.23*
Total CO_2 Pipeline Transmission and Storage System (\$/GJ H_2)	**0.39**	**0.59**

Task 1.4. Modeling H_2 Demand Centers

Designing a hydrogen fuel delivery infrastructure depends on the characteristics of the hydrogen demand. We model the magnitude, spatial distribution, and time dependence of hydrogen demand, based on Geographic information system (GIS) data on vehicle populations, and projections for energy use in hydrogen vehicles, and market penetration rates. Our method for calculating a hydrogen demand map is described below (see Figure 12).

- First, the total numbers of light duty vehicles are mapped as a function of location (vehicles/km^2). This map is based on US census data. If information is known about the locations of fleets, this could be shown as well.
- Next, a market penetration rate for hydrogen is estimated (fraction of new vehicles using hydrogen). This could be done in various ways. For example, one could assume that a "ZEV mandate" is put in place, so that a fixed fraction of new vehicles sold must use hydrogen. Alternatively, one could devise other criteria for estimating how many new hydrogen vehicles are sold each year, based on projections of when they become competitive with competing technologies like gasoline internal combustion engine technologies. From the market penetration rate, the number of hydrogen vehicles can be found as a function of location and time (H_2 vehicles/km^2 versus time).
- The hydrogen use per vehicle (kg H_2/d/vehicle) is estimated from assumptions about hydrogen vehicle fuel economy and miles travelled. A map of hydrogen demand density versus location and time can be calculated (kg/d/km^2). This is shown in Figure 9, for the state of Ohio. The lighter colors are low demand density, the darker colors higher density. The cities of Cleveland, Columbus and Cincinnati are obvious areas of high demand.

Once the hydrogen demand density is known, one has to decide how many refueling stations are required and where they should be sited. The number, location and size of refueling stations have a major effect of the cost of infrastructure. Again, GIS data can help guide the process of siting and sizing refueling stations. Let's assume we want future hydrogen stations to be as convenient as today's gasoline stations. In the United States, on average, there is one gasoline refueling station for every 2000 light duty vehicles (Davis 2000). GIS maps can be used to show where gasoline stations are located. For several cities we examined, stations tend to cluster along major roads in "spoke" or "ring" like patterns. Often, more than one station is found at major intersections or at freeway exits. This suggests that today's convenience level could be preserved, if perhaps 25% of current gasoline stations offered hydrogen. For typical US urban vehicle densities of 1000-2000 cars/km^2, there is one gasoline station per 1-2 km^2. Equal convenience might be found with one hydrogen station per 4-8 km^2. If we know the hydrogen demand per km^2, we can find the amount of hydrogen needed at each station as a function of time. This simple hydrogen demand model will be improved in future work.

Task 1.5. Modeling H_2 Infrastructure

We assume that a gaseous pipeline distribution network is used to bring hydrogen from the fossil energy complex to refueling stations where it is dispensed to vehicles as a compressed gas.. The infrastructure includes hydrogen compression and storage at the hydrogen production plant, pipeline transmission from the hydrogen plant to the hydrogen demand (assuming that the hydrogen plant is located some distance from the city), recompression for local pipeline distribution (this might or might not be needed depending on the distance between the hydrogen plant and the demand), a local pipeline distribution network, and hydrogen refueling stations.

Modeling Hydrogen Distribution System Components

We use an extensive data-base and technical/economic models of H_2 infrastructure (pipelines, refueling stations) developed by the principal investigator as part of earlier studies for the USDOE Hydrogen Program (Ogden 1998, Ogden 1999). In addition, we compare these costs with those of other hydrogen system analysts (Directed Technologies 1997, Thomas et al. 1998, Mintz et al. 2002, Amos 1999). Models for hydrogen infrastructure components are described in detail in Appendix E.

Hydrogen compression

Hydrogen must be compressed from production pressure (typically 200 psia or 1.4 MPa) to higher pressure for storage or pipeline transmission. In our base case, we assume that hydrogen is compressed to 6.8 MPa (1000 psia) for pipeline transmission and distribution. For storage on vehicles we compress to 6000 psia at the refueling station for on-board storage at 5000 psia.

Equations for hydrogen compressor power requirements and costs are developed in Appendix E. The energy requirements for hydrogen compression are shown as a function of inlet pressure and outlet pressure in Figure 14. Electricity needed for compression is about 5-10% of the energy content of the hydrogen on a higher heat value basis, depending on the inlet and outlet pressures. We note that the compression energy requirements increase faster at higher outlet pressure because of the non-ideal behavior of hydrogen gas at high pressure. (The compression energy requirements are higher for hydrogen as compared to natural gas, by roughly a factor of three. For the same energy flow rate and pressure difference, the capital cost of a hydrogen compressor is about 4 times that of a natural gas compressor.)

Compression typically adds less than $1/GJ to the cost of hydrogen, depending on the flow rate and the inlet and outlet pressures, and electricity cost. Most of this cost is due to the electricity cost, rather than the compressor capital cost. (See Appendix E for details.)

Hydrogen Storage

In the case of large centralized fossil hydrogen production, it is desirable to run the hydrogen production plant continuously. However, the system-wide demand profile for transportation fuel will vary over the day, weekly and even seasonally, so that some storage capacity (about 12 to 24 hours of production) will be needed in the system. For a hydrogen pipeline distribution system, several options are available.

> 1) *Hydrogen could be stored in the pipeline.* No extra capital costs would be incurred, although some extra compression might be required. The viability of this option depends on the pipeline length and operating pressures as well as the demand profile. For example, with inlet pressure of 500 psia and outlet pressure of 200 psia a pipeline 30 km in length, and 3 inches in diameter could be used to transmit 5 million scf/day. The total storage volume available would be about 19000 cubic feet. If the pipeline pressure were raised to 1000 psia, if would be possible to store about 1.3 million scf in the pipeline or about 6 hours production from a system producing 5 million scf/day. Depending on the demand profile, this might be sufficient.
>
> 2) *Hydrogen could be stored at the refueling station.* Storage cylinders would be available to accept the nighttime production of hydrogen, delivered by pipeline. Since some storage is already required at the station to meet demand peaks, this storage strategy would increase the filling station contribution to the delivered cost of hydrogen by only about $0.2-0.5/GJ. This is the option chosen in our designs, where we assume that 6 hours of storage is located at the station. This storage could also provide some back-up for pipeline outages.
>
> 3) *Hydrogen could be stored at the production site*. This would add costs for compression and storage of perhaps 2 dollars per GJ of hydrogen. This option is also used in our study, where is is assumed that 12 hours of bulk central storage is used.

Bulk gaseous storage at the central plant can be accomplished in several ways (Taylor et.al 1986). First hydrogen is compressed from production pressure (typically 200 psi for steam reforming or gasification systems) to storage pressure of perhaps 1000 psi (assuming that the pipeline will be fed from storage). For very large quantities (on the order of 100 million scf or more), underground gas storage might be used. Capital costs for underground storage are typically $2000-3000 per GJ of hydrogen storage capacity (Taylor et al. 1986)

Otherwise, above ground pressure vessels are favored. High pressure (1000-8000 psi) bulk hydrogen storage in standard aboveground pressure cylinders costs about $4000-5000/GJ of hydrogen stored. A 1997 study by Air Products and Chemicals (Directed Technologies et al. 1997) gave costs for high pressure (5000 psia) gas storage of $11.7 million for a system storing 17 tonnes H_2 and $117 million for a system storing 170 tonnes H_2. There appears to be no economy of scale for storage in pressure cylinders. The capital cost is about $5000/GJ. (It is interesting to note that advanced composite high pressure cylinders for storing hydrogen on vehicles are projected to cost about $1500 per GJ of stored hydrogen capacity, at 5000 psia. So it is conceivable that future capital costs for storage might be reduced.)

Our base case hydrogen plant with an output of 1000 MW H2 produces 86,400 GJ/day. So 1/2 day's storage would be 43,200 GJ and would cost

$5000/GJ x 43200 GJ = $216 million

The levelized cost of storage is about $1.6/GJ hydrogen.

We have focussed on gaseous hydrogen storage, but it is also possible to liquefy hydrogen (at 20 K), store it in a cryogenic dewar and deliver it to refueling stations via cryogenic tank truck as a liquid. Liquid hydrogen storage is preferred when small quantities of hydrogen must be shipped long distances.

Hydrogen Pipelines

The cost of a hydrogen pipeline depends on the pipeline diameter and length. If the flow rate, pipeline length and inlet and outlet pressures, temperatures and gas properties are known, we can use steady-state fluid flow equations to estimate the pipeline diameter and the cost. In some cases, it may be desirable to add "booster" compressors along the pipeline to recompress the gas.

In Appendix E, we develop equations for hydrogen pipeline transmission costs as a function of pipeline flow rate and length.

The levelized cost of the hydrogen pipeline (not including compression or storage) is given approximately by:

$$C_{pipe}\ (\$/GJ) = 0.15 \times [Q\ (MW)/\ 1000\ MW]^{-0.5} \times (L/100\ km)^{1.25}$$

Levelized costs are shown for hydrogen pipeline transmission including compression, storage at the central plant, and the pipeline are shown Figure 15, as a function of pipeline length and flow rate.

We see that long distance transmission can add up to a few dollars per GJ to the cost of hydrogen. Costs scale inversely with hydrogen flow rate and almost linearly with distance.

Local hydrogen pipeline distribution

Once hydrogen is delivered to the city gate, it must be distributed to refueling stations. This could be accomplished via truck or small scale pipelines. For a large, geographically dense demand, hydrogen pipeline distribution promises the lowest cost, so we focus on this alternative.

Hydrogen can be delivered from a central production point to refueling stations via small scale pipelines (Ogden et.al 1995, Ogden et.al. 1996). We assume that a 3" hydrogen pipeline capable of operation at up to 1000 psi costs $1 million per mile installed. The flow rate of hydrogen through the line can be estimated as shown in Figure 16. The levelized cost of hydrogen pipeline delivery is roughly

Cost of pipeline delivery ($/GJ) =

1.2 x (pipeline length in km) x (installed cost in million$/mile) /(hydrogen flow rate in million scf.day)

The extent of the pipeline system needed depends on the geographical density of the demand.

For a pipeline distribution system with radial “spokes”, sketched in Figure 17, the delivery cost can be calculated as a function of numbers of cars per km2 (Figure 18). We see that densities less than about 200 cars/km2, the cost of pipeline distribution increases rapidly. For a low density of cars, other distribution modes are preferred.

Modeling Hydrogen Refueling Stations

H_2 is dispensed to vehicles at refueling stations as a high-pressure gas for storage in onboard cylinders (at 34 MPa). It is estimated that a refueling station dispensing 2.4 tonnes (1 million standard cubic feet) of H_2 per day costs $1.5 million, adding $6.1/GJ to the delivered cost of H_2 (see Table 12 and Appendix E) (Ogden 1998). About 80% of the capital cost and 50% of the levelized cost is due to H_2 compression at the station and storage cylinders. The remainder is due to capital for dispensers and controls, and labor costs. The cost of on-board H_2 storage is not included. This suggests that development of a new H_2 storage technology that requires less capital and energy input than compressed gas could reduce refueling station costs.

Hydrogen Delivery Cost for 1000 MW H2 Base Case

For our base case 1000 MW hydrogen plants, costs for H_2 distribution and refueling systems are shown in Table 12 (see Appendix E for details). We assume that coal-derived H_2 is transmitted 100 km to the "city gate", where it is recompressed and enters a local network bringing H_2 to refueling stations. Natural gas-derived H_2 is produced at the city gate. Based on the flow equations in (Christodoulou 1984, Mohitpour 2000) the optimal 100 km H_2 transmission pipeline diameter is 0.29 m, and the associated cost is \$0.13/GJ, for a 1000 MW plant and pipeline inlet and outlet pressures of 6.8 MPa and 1.4 MPa, respectively. (For long distance pipelines, capital costs are taken from (Christodoulou 1984) and recent industry estimates (Jandrain 2001).)

For an alternative H_2 energy flow rate Q (assuming Q>500 MW) and pipeline length L, the levelized cost of a hydrogen pipeline can be estimated as (\$0.13/GJ) x $(Q/1000\ \text{MW})^{-0.5}$ x $(L/100\ \text{km})^{1.25}$.

For local H_2 distribution within a city via small (0.1-0.2 m diameter) high pressure pipelines, we assume the installed cost of the H_2 pipelines is \$622/m (\$1,000,000 per mile), independent of pipeline diameter (Ogden 1999). We assume that H_2 is distributed radially outward from a central hub through "spokes," along which the pressure drops from 6.8 MPa to no less than 1.4 MPa at the outermost refueling stations. For our base case, each of 10 spokes has 25 refueling stations, each dispensing 2.4 tonnes (1 million standard cubic feet) of H_2 per day. Assuming an 80% capacity factor, this is matched to 5600 cars per station. For a geographically dense demand of 750 H_2 cars/km^2 (about half the average density of cars in the Los Angeles area), each "spoke" is 28 km long. The levelized cost for pipeline capital for this local H_2 distribution system is \$1.29/GJ. The cost of local pipeline distribution depends on geographic density of hydrogen vehicles as shown in Figure 12.

An important component of the distribution system is above-ground H_2 storage at the central H_2 plant, with capacity equivalent to one half day's production. This storage is needed to assure supply in case of outages and to account for time variations in H_2 demand. We assume a capital cost of \$5000 per GJ of H_2 storage capacity for storage cylinders, or \$216 million, based on current industrial bulk compressed H_2 gas container technology. The levelized cost contribution of central H_2 storage is significant, \$1.63/GJ(H_2). Lower cost bulk storage is clearly desirable, where possible; underground storage in aquifers or salt caverns is likely to be less costly [Ogden 1999]. (For comparison, at high levels of mass production (300,000/y) the capital cost of onboard high pressure H_2 cylinders for cars is projected to be about \$1500 per GJ of storage capacity [Thomas et al. 1998].)

At lower H_2 demand density, the cost contribution of local pipeline distribution increases as $(1/\text{vehicle density})^{0.5}$, while the central storage cost is insensitive to scale. Below a certain demand density, non-pipeline H_2 distribution or onsite H_2 production will provide a lower delivered cost.

Table 12. H_2 Delivery System For 1000 MW H_2 Plant Serving 1.4 Million H_2 Cars

	H_2 from natural gas	**H_2 from coal**

H_2 Distribution and Refueling System Capital Cost (million \$)		
Central H_2 Plant Buffer Storage(1/2 day's output of H_2 Plant)	216	216
H_2 Pipeline from H_2 Plant to City Gate 100 km(coal only)		47
Citygate H_2 Booster compressor (24 MWe)		18
H_2 Local Distribution Pipelines (750 cars/km^2)	171	171
Sub-total H_2 Distribution (excluding refueling stations)	*387*	*452*
H_2 Refueling Stations (252 stations)	375	375
Total	*762*	*827*
Levelized Cost of H_2 Distribution and Refueling (\$/GJ H_2)		
Central H_2 Plant Buffer Storage	1.63	1.63
H_2 Pipeline from H_2 Plant to City Gate 100 km (coal only)		0.15
Citygate H_2 Booster compressor (coal only)		0.55
H_2 Local Distribution Pipelines	1.29	1.29
Sub-total H_2 Distribution (excluding refueling station).	*2.92*	*3.07*
H_2 Refueling Station	6.06	6.06
Total	*8.98*	*9.68*

The overall costs of distribution and refueling are $9-10/GJ of hydrogen, about $6/GJ of which is due to refueling.

Task 2.0. Integrated Studies of the Entire System to Find the Lowest Cost Options

We now combine our "component" models of hydrogen production, CO2 capture, transmission and sequestration, hydrogen compression, storage, distribution and refueling to describe an integrated system.

In Task 2.1, as a first step, we seek to better understand the total system design and economics, for the special case of a single large fossil energy complex connected to a single geological CO_2 sequestration site and a single H_2 demand center (such as a city with a large concentration of H_2 vehicles). This system is shown in Figure 1. Using the component models from Task 1, we developed a simple analytical model linking the components into a total system. We developed "cost functions" for the CO_2 disposal cost and the delivered H_2 cost with explicit dependence on the many input parameters described in Task 1 above (e.g. size of demand, fossil energy complex process design, aquifer physical characteristics, distances, pressures etc.). We then estimate the total delivered cost of H_2 with CO_2 sequestration for a number of cases of interest. Sensitivity studies of this "simple system" provide us with insights on which parameters are most important in determining delivered hydrogen costs. The model developed here could be extended to fossil H_2 energy systems that include multiple fossil energy complexes, H_2 demand centers and CO_2 sequestration sites.

Although studies of a simple system are useful, a mature fossil hydrogen system would potentially involve a number of hydrogen production sites, hydrogen demand centers, and CO2 sequestration sites. To study more complex and realistic systems involving multiple energy complexes, H_2 demand centers, and sequestration sites, we are exploring use mathematical programming methods to find the lowest cost system design. This work (Task 2.2) will be described in future reports.

The goal of our system modeling is to distill "rules for thumb" for developing H_2 and CO_2 infrastructures.

Task 2.1. Develop Simple Model for Entire System and Perform Sensitivity Studies

In this task, we estimate the delivered costs for hydrogen from coal and natural gas, including CO2 sequestration. The base case 1000 MW hydrogen production systems are described in Table13 and Figure 19. The CO2 disposal systems for these plants are described in Table 11. The hydrogen delivery system is described in Table 12.

Table 13. 1000 MW Fossil H_2 Production Plants W/CO_2 Capture And Compression

	H_2 from Natural Gas [Table 4]	**H_2 from Coal [Table 8]**
Electricity net production MWe	0	31
First law efficiency, HHV =(H_2 + $elec_{out}$)/$Feedstock_{in}$	78%	68.7%
CO_2 emitted (tonne/h) at full capacity	36	34
CO_2 captured (tonne/h) at full capacity	204	406
Installed Capital Cost of H_2 Plant (million \$)	429	731
Levelized Cost of H_2 Production (\$/GJ HHV)		
Plant capital (=15% of capital cost)	2.56	4.35
Non-fuel O&M	0.39	1.00
Byproduct electricity credit	--	-0.26
Feedstock	4.71	1.41
Total	7.66	6.50

In Figures 20 and 21, we summarize our results for 1000 MW H_2 plants based on natural gas and coal, with CO_2 capture.

System Capital Cost For the "fully developed" H_2 economy described here, serving a geographically concentrated market of 1.4 million H_2 cars, the total system capital cost varies from about \$1200-1600 million or \$900-1200/car (see Figure 20). H_2 pipeline distribution systems and refueling stations, together, contribute about 1/2 to 2/3 of the total capital cost. These costs are dominated by H_2 compression and storage cylinders. This highlights the importance of developing better H_2 storage methods that require lower energy inputs and costs than high pressure compressed gas. H_2 production systems are also major contributors to the system capital cost, with coal plants about 1.7 times as capital intensive as natural gas plants. For our assumptions (100 km pipeline, and desirable reservoir characteristics), CO_2 pipelines and wells contribute only about 5% to the system capital cost. The incremental total system capital cost of sequestration for the 1 GW H_2 system considered here, relative to the same system without sequestration, is about 20% (3%) for natural gas (coal) H_2 energy systems (Foster Wheeler 1996, Kreutz et al. 2002).

Delivered Cost of Hydrogen For our base case, the delivered cost of H_2 is about $17.0 (16.9)/GJ for H_2 from natural gas (coal) (Figure 21). H_2 production, distribution and refueling contribute 45% (38%), 17% (22)% and 35% (36)%, respectively. CO_2 capture, compression, pipeline transmission and storage add about $1.7 (1.5)/GJ (~10%) to the delivered cost of H_2 transportation fuel compared to cases where CO_2 is vented. Of this, only about $0.39(0.59)/GJ or 2% (3%) is due to the CO_2 pipeline and storage. Delivered H_2 costs are sensitive to scale economies in both H_2 production and pipeline transmission. Geographic density of demand is key to the economic viability of widespread gaseous H_2 distribution. In the early stages, when demand is relatively low and geographically diffuse, trucked-in H_2 or distributed H_2 production (e.g., via small scale natural gas reforming at refueling sites) would be preferred from a cost perspective (Ogden 1999).

Major Sensitivities: For our base case assumptions (large CO_2 and H_2 flows; a relatively nearby reservoir for CO_2 sequestration with good injection characteristics; a large, geographically dense H_2 demand), H_2 production, distribution and refueling were found to be the major costs contributing to the delivered H_2 cost. CO_2 capture and sequestration added only ~10%. Better methods of H_2 storage would reduce both refueling station and distribution system costs, as well as costs on-board vehicles. The models developed here will be used in a future regionally specific case study of H_2 infrastructure development with CO_2 sequestration, involving multiple sources and sinks for CO_2 and multiple H_2 demand sites.

Task 2.2 Explore Use of Mathematical Programming Techniques to Study More Complex Systems.

Work on this task is still preliminary and will be described in future technical reports.

Task 3.0 Case Study of Transition to a Fossil Energy System with CO_2 Sequestration

In this task, we plan to explore transition strategies: how H_2 and CO_2 infrastructures might develop in time, in the context of a geographically specific regional case study. We focus on the Midwestern United States, a region where coal is widely used today in coal-fired power plants, and good sites for CO_2 sequestration are available. The goal is to identify attractive transition strategies toward a regional hydrogen/electricity energy system in the Midwest with near zero emissions of CO_2 and air pollutants to the atmosphere.

In this task, we hope to derive insights about.

- Time constants and costs. How fast can we implement hydrogen fuel infrastructure? How much will it cost? What are the best strategies? What level of demand is needed for widespread implementation of H_2 energy system?

- Sensitivities to: technology performance and costs, size and density of demand, local availability of primary sources, characteristics of CO_2 sequestration sites, market growth, policies.

- Rules for thumb for optimizing H_2 and CO_2 infrastructure development.

To better visualize our results, we plan use a geographic information system (GIS) format to show the location of H_2 demand, fossil energy complexes, coal resources, existing infrastructure (including rights of way), CO_2 sequestration sites and the optimal CO_2 and H_2 pipeline networks. As an initial step, a survey of relevant GIS data sets was conducted, and initial work was begun on building a database.

Results from this task are still very preliminary and will be described in more detail in future technical reports.

CONCLUSION

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During the first six months of research under this contract, we have made significant progress toward understanding the systems aspects of fossil hydrogen systems with CO2 sequestration, and meeting our objectives for the overall project.

Task 1. We have implemented simplified cost and performance models of the main components of a fossil hydrogen energy system with CO2 sequestration. These include hydrogen production systems with CO_2 capture, hydrogen compression and storage systems, hydrogen pipelines, hydrogen refueling stations, CO_2 compression, CO_2 pipelines, and CO_2 injection sites. These models are based on cost and performance estimates for system components that are available in public domain literature, and from ongoing work at Princeton University's Carbon Mitigation Initiative. In addition, we have described a simple method for modeling hydrogen demand based on GIS data about population densities.

Task 2. We used the individual component models developed in Task 1, to study simplified large-scale fossil H_2 energy systems with CO_2 sequestration, consisting of a single fossil energy complex, a single demand center (city) and a single CO2 sequestration site. We have identified the major factors contributing to the delivered cost of H_2, and their most important sensitivities. For our base case assumptions (large CO_2 and H_2 flows; a relatively nearby reservoir for CO_2 sequestration with good injection characteristics; a large, geographically dense H_2 demand), H_2 production, distribution and refueling were found to be the major costs contributing to the delivered H_2 cost. CO_2 capture and sequestration added only ~10%. Better methods of H_2 storage would reduce both refueling station and distribution system costs, as well as costs on-board vehicles. The models developed here will be used in a future regionally specific case study of H_2 infrastructure development with CO_2 sequestration, involving multiple sources and sinks for CO_2 and multiple H_2 demand sites.

We have begun to explore use of mathematical programming as a tool for understanding more complex fossil hydrogen energy systems with multiple sources for CO2 and multiple sinks (sequestration sites). This work is still preliminary and results will be reported in later technical reports.

Task 3. We have begun to gather the GIS data needed to carry out a case study of developing a hydrogen energy system in the Mid-western US. This effort is still preliminary and results will be given in future technical reports.

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LIST OF ACRONYMS AND ABBREVIATIONS

CMI	Carbon Mitigation Initiative. Begun in 2001, the Carbon Mitigation Initiative is a ten-year $15-20 million dollar joint project of Princeton University, BP and Ford Motor Company to find solutions to global warming and climate change.
FCV	fuel cell vehicle
GIS	geographic information system
GJ	gigajoule (= 10^9 Joules)
MW	Megawatts (=10^6 Watts)
POX	partial oxidation
PSA	pressure swing adsorption
scf	standard cubic foot
SMR	steam methane reforming.
USDOE	United States Department of Energy Research
VSA	vacuum swing adsorption

Figure 1.

A Fossil Energy System for Production of Hydrogen and Electricity with CO_2 Sequestration. *(Variables for the Study are Shown in Italics)*

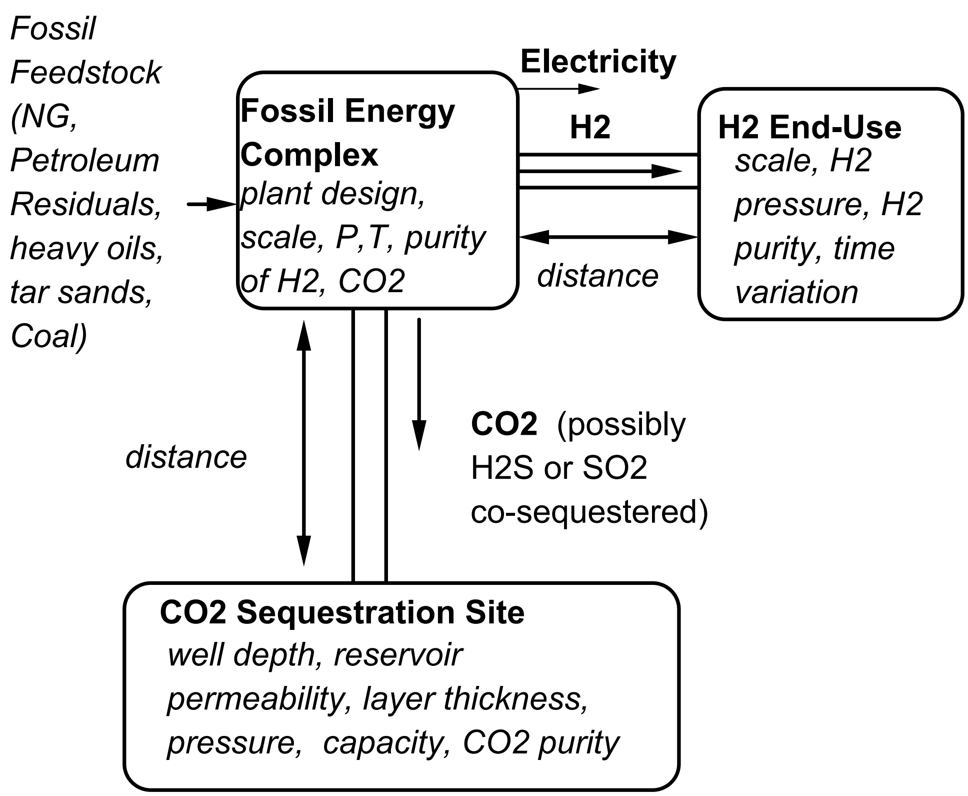
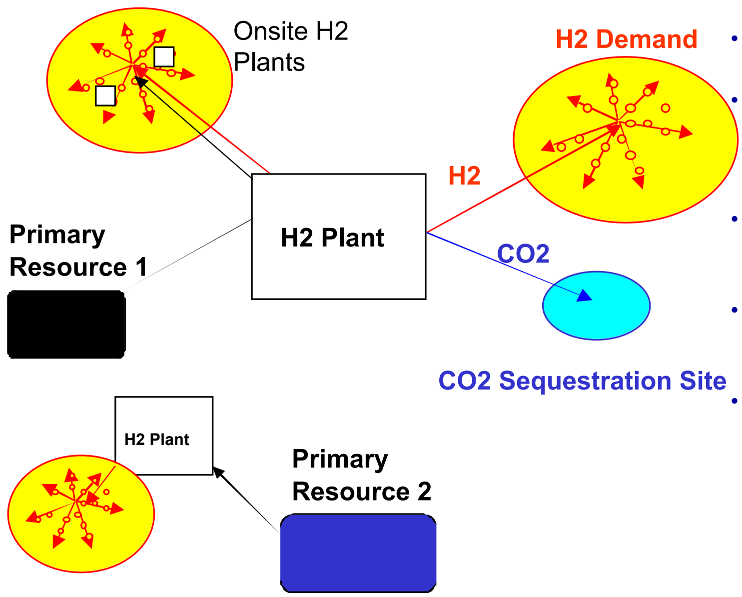


Figure 2.

More Complex System: Optimization for Low Delivered H_2 Cost

What is the lowest cost system for producing and delivering H_2 to serve a growing demand?



- **H_2 Plants: Size and Location?**
- **Resources for H2 production: Characteristics, distance from H_2 plant?**
- **Use existing energy infrastructure/rights of way?**
- **Optimum paths for H_2 infrastructure over time?**
- **Design problem is different than typical oil or gas pipeline systems w.r.t time frame and complexity**

Figure 3.

FIG.2. HYDROGEN PRODUCTION FROM NATURAL GAS WITH AND WITHOUT CO2 CAPTURE

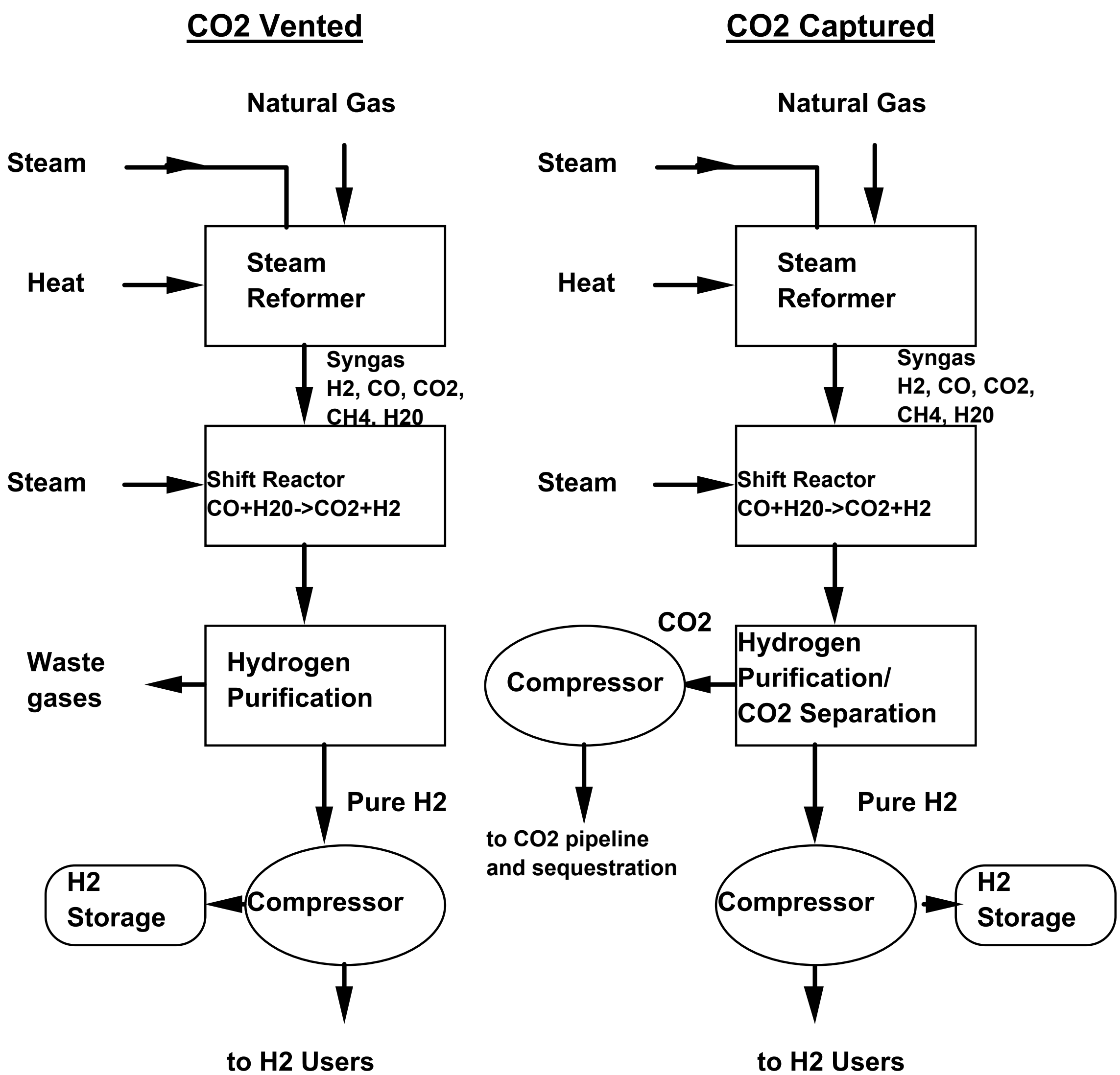


Figure 4.

FIG. 3. PRODUCTION OF ELECTRICITY AND H2 FROM COAL WITH CO2 CAPTURE

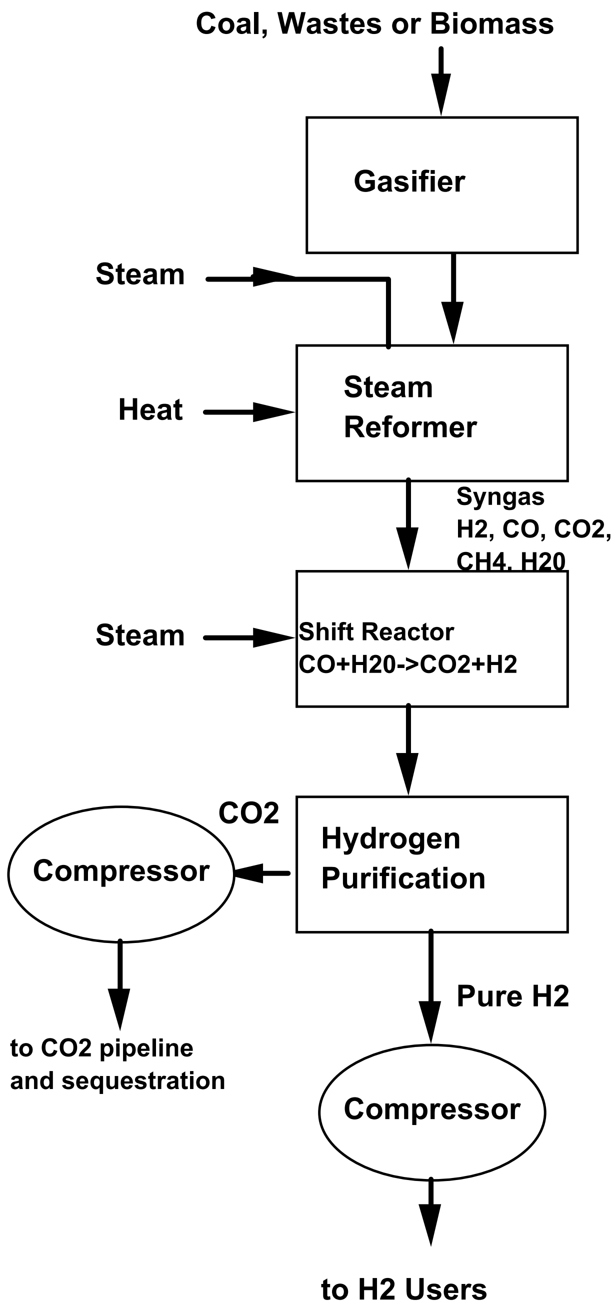
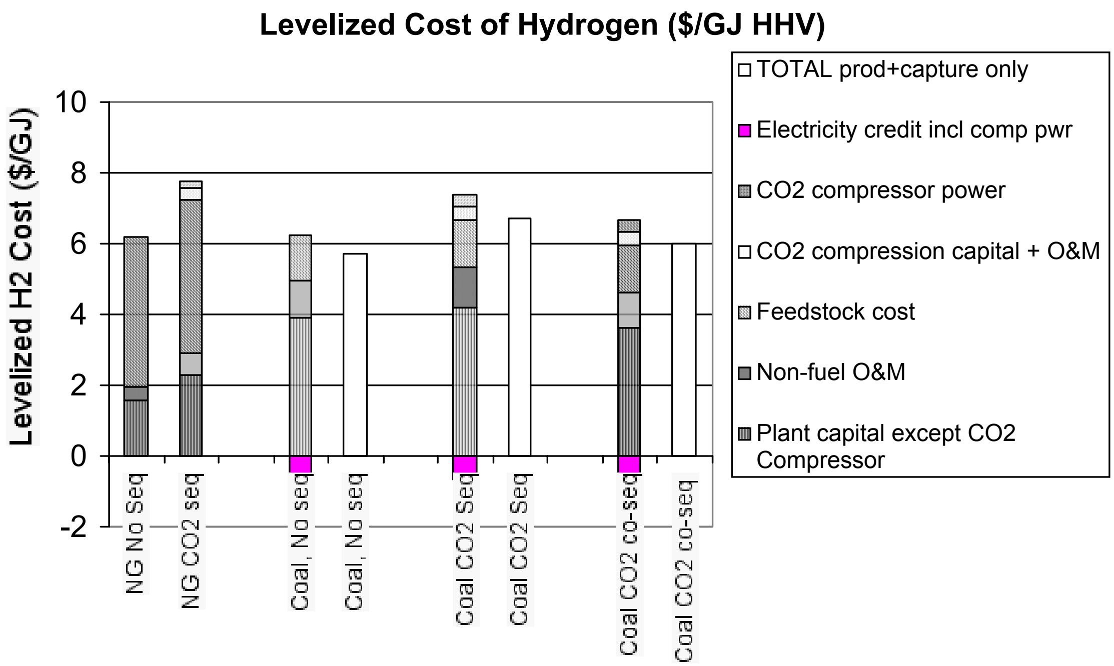


Figure 5.


Levelized Cost of Hydrogen ($/GJ HHV)
Levelized H2 Cost ($/GJ)
10
8
6
4
2
0
-2
NG No Seq
NG CO2 seq
Coal, No seq
Coal, No seq
Coal CO2 Seq
Coal CO2 Seq
Coal CO2 co-seq
Coal CO2 co-seq
TOTAL prod+capture only
Electricity credit incl comp pwr
CO2 compressor power
CO2 compression capital + O&M
Feedstock cost
Non-fuel O&M
Plant capital except CO2 Compressor

Figures 6 and 7.

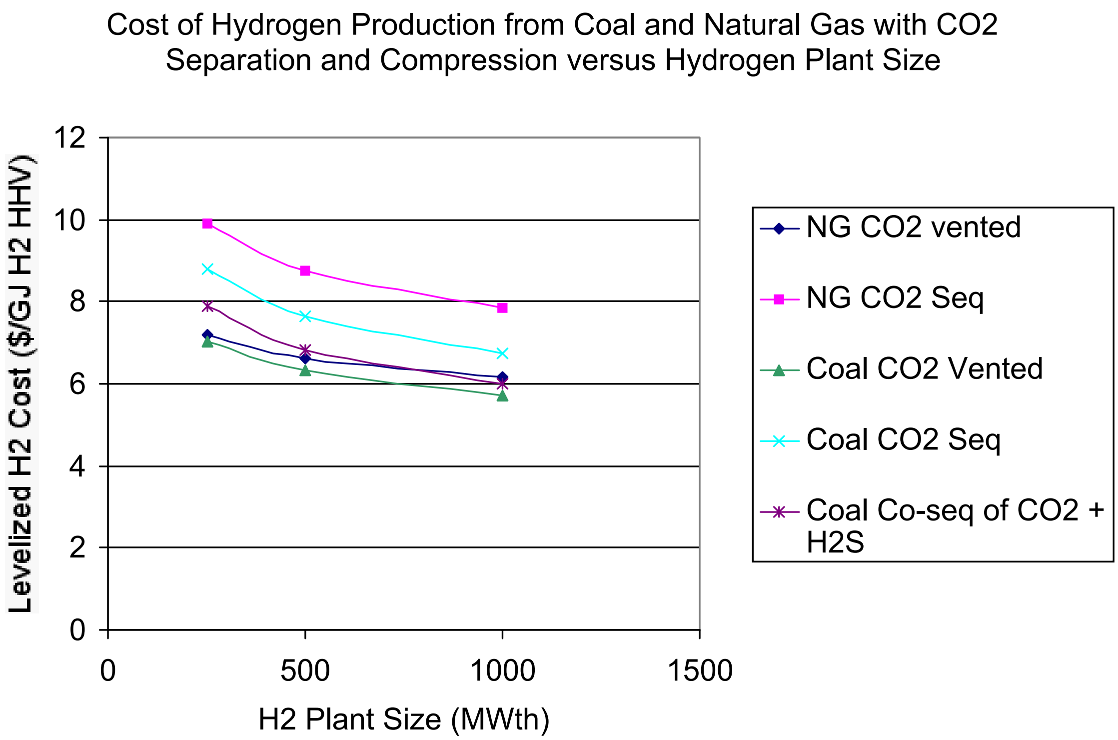
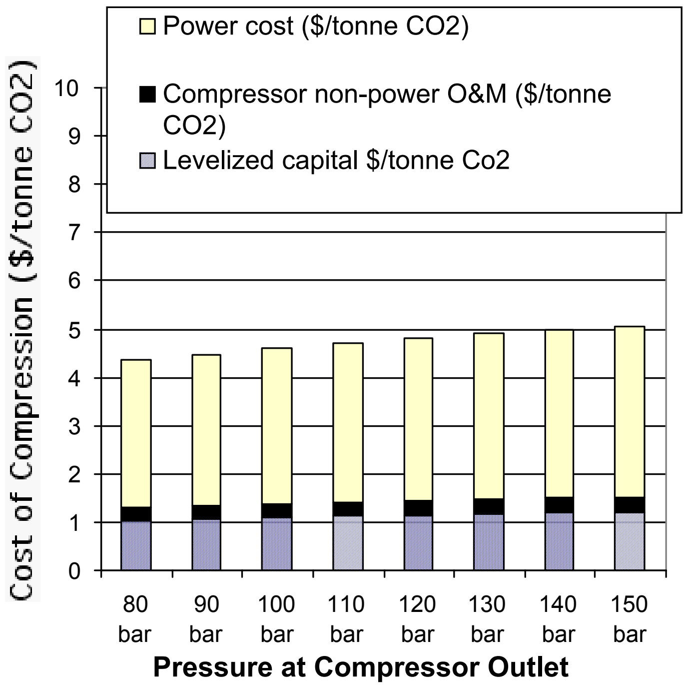
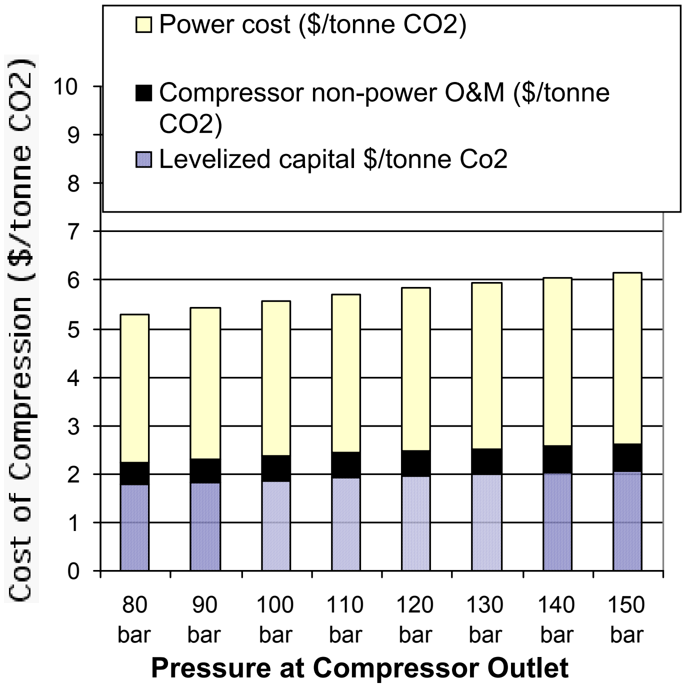


Figure 8.



Power cost ($/tonne CO2)
Compressor non-power O&M ($/tonne CO2)
Levelized capital $/tonne Co2
Cost of Compression ($/tonne CO2)
0
1
2
3
4
5
6
7
8
9
10
80 bar
90 bar
100 bar
110 bar
120 bar
130 bar
140 bar
150 bar
Pressure at Compressor Outlet

Figure 9



Power cost ($/tonne CO2)
Compressor non-power O&M ($/tonne CO2)
Levelized capital $/tonne Co2
Cost of Compression ($/tonne CO2)
10
9
8
7
6
5
4
3
2
1
0
80 bar
90 bar
100 bar
110 bar
120 bar
130 bar
140 bar
150 bar
Pressure at Compressor Outlet

Figure 10

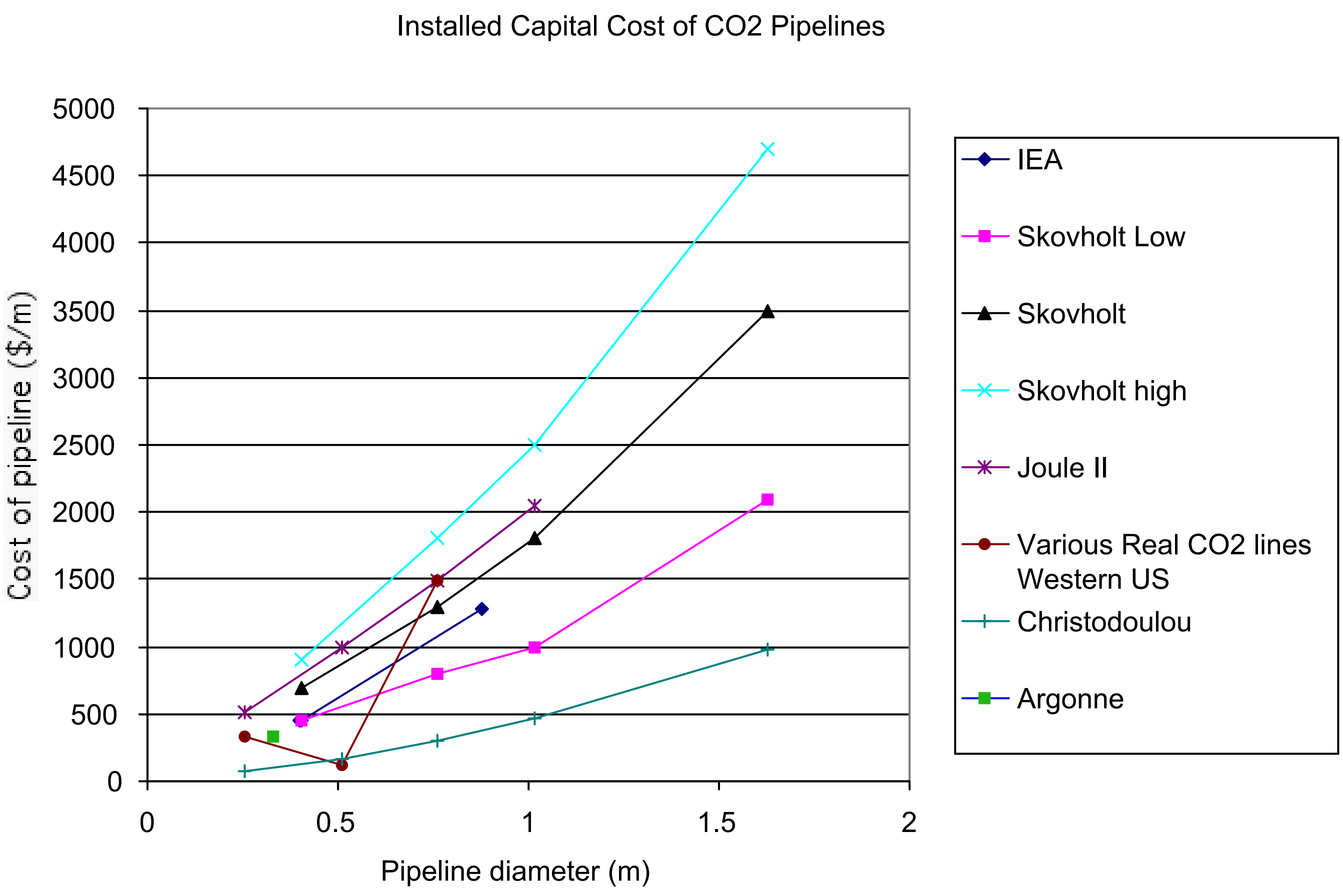
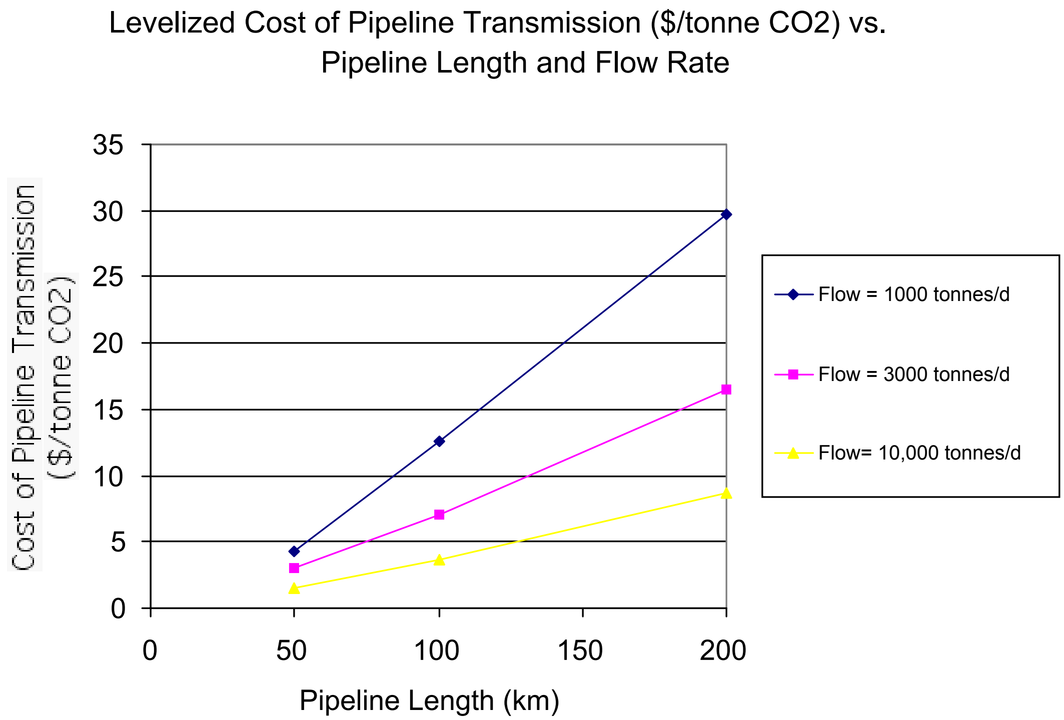

Installed Capital Cost of CO2 Pipelines
Cost of pipeline ($/m)
5000
4500
4000
3500
3000
2500
2000
1500
1000
500
0
0
0.5
1
1.5
2
Pipeline diameter (m)
IEA
Skovholt Low
Skovholt
Skovholt high
Joule II
Various Real CO2 lines Western US
Christodoulou
Argonne

Figure 11.



Levelized Cost of Pipeline Transmission ($/tonne CO2) vs.
Pipeline Length and Flow Rate
Cost of Pipeline Transmission
($/tonne CO2)
35
30
25
20
15
10
5
0
0
50
100
150
200
Pipeline Length (km)
Flow = 1000 tonnes/d
Flow = 3000 tonnes/d
Flow= 10,000 tonnes/d

Figure 11b.

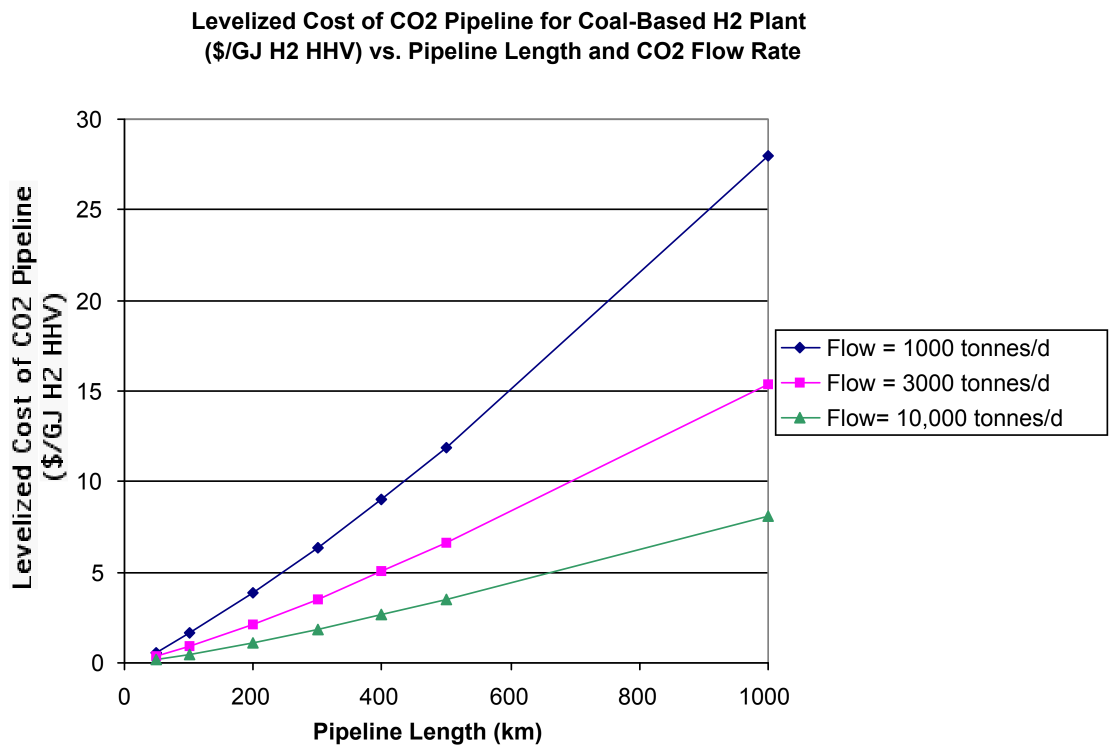

Levelized Cost of CO2 Pipeline for Coal-Based H2 Plant
($/GJ H2 HHV) vs. Pipeline Length and CO2 Flow Rate
Levelized Cost of CO2 Pipeline
($/GJ H2 HHV)
30
25
20
15
10
5
0
0
200
400
600
800
1000
Pipeline Length (km)
Flow = 1000 tonnes/d
Flow = 3000 tonnes/d
Flow= 10,000 tonnes/d

Figure 11c.

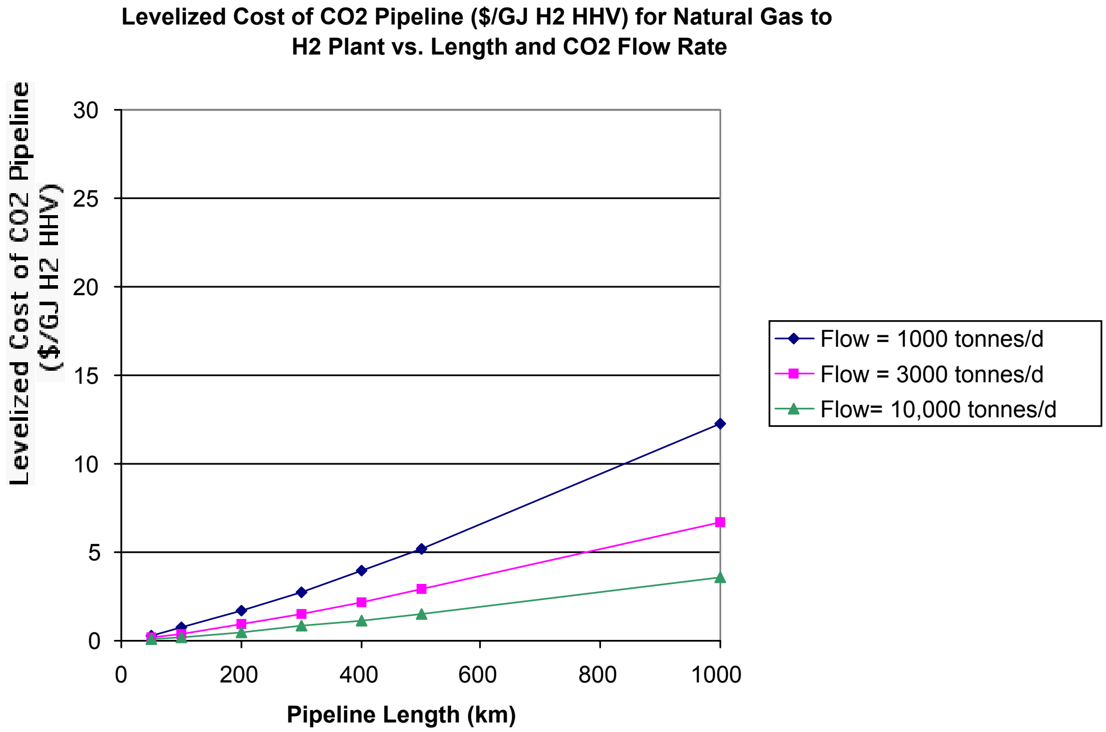

Levelized Cost of CO2 Pipeline ($/GJ H2 HHV) for Natural Gas to H2 Plant vs. Length and CO2 Flow Rate
Levelized Cost of CO2 Pipeline ($/GJ H2 HHV)
30
25
20
15
10
5
0
0
200
400
600
800
1000
Pipeline Length (km)
Flow = 1000 tonnes/d
Flow = 3000 tonnes/d
Flow= 10,000 tonnes/d

Figure 12.

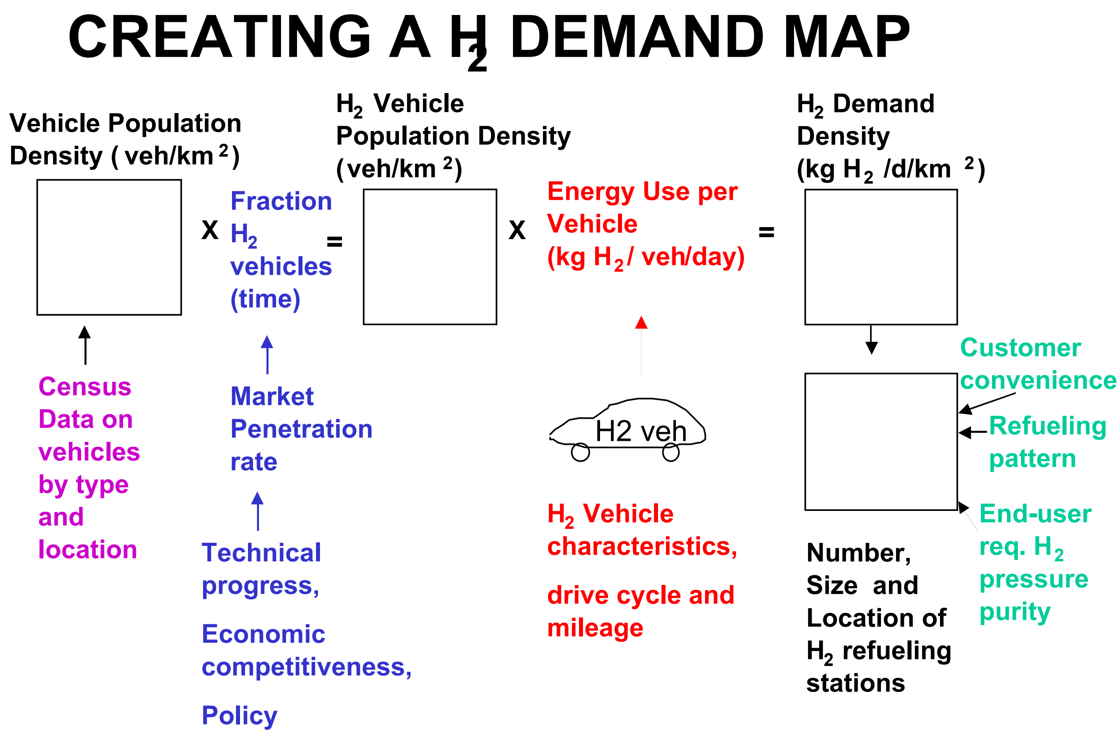

CREATING A H_2 DEMAND MAP
Vehicle Population Density (veh/km ^{2})
X
Fraction H_2 vehicles (time)
=
H_2 Vehicle Population Density (veh/km ^{2})
X
Energy Use per Vehicle (kg H_2/ veh/day)
=
H_2 Demand Density (kg H_2 /d/km ^{2})
Census Data on vehicles by type and location
Market Penetration rate
Technical progress,
Economic competitiveness,
Policy
H2 veh
H_2 Vehicle characteristics,
drive cycle and mileage
Customer convenience
Refueling pattern
End-user req. H_2 pressure purity
Number, Size and Location of H_2 refueling stations

Figure 13.

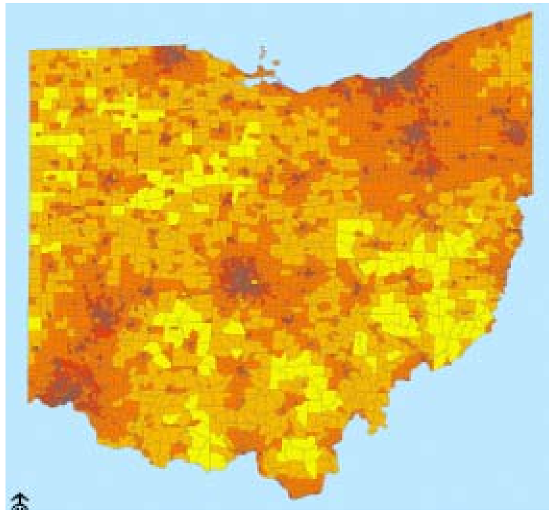


Figure 14.

Energy Requirement for Hydrogen Compression

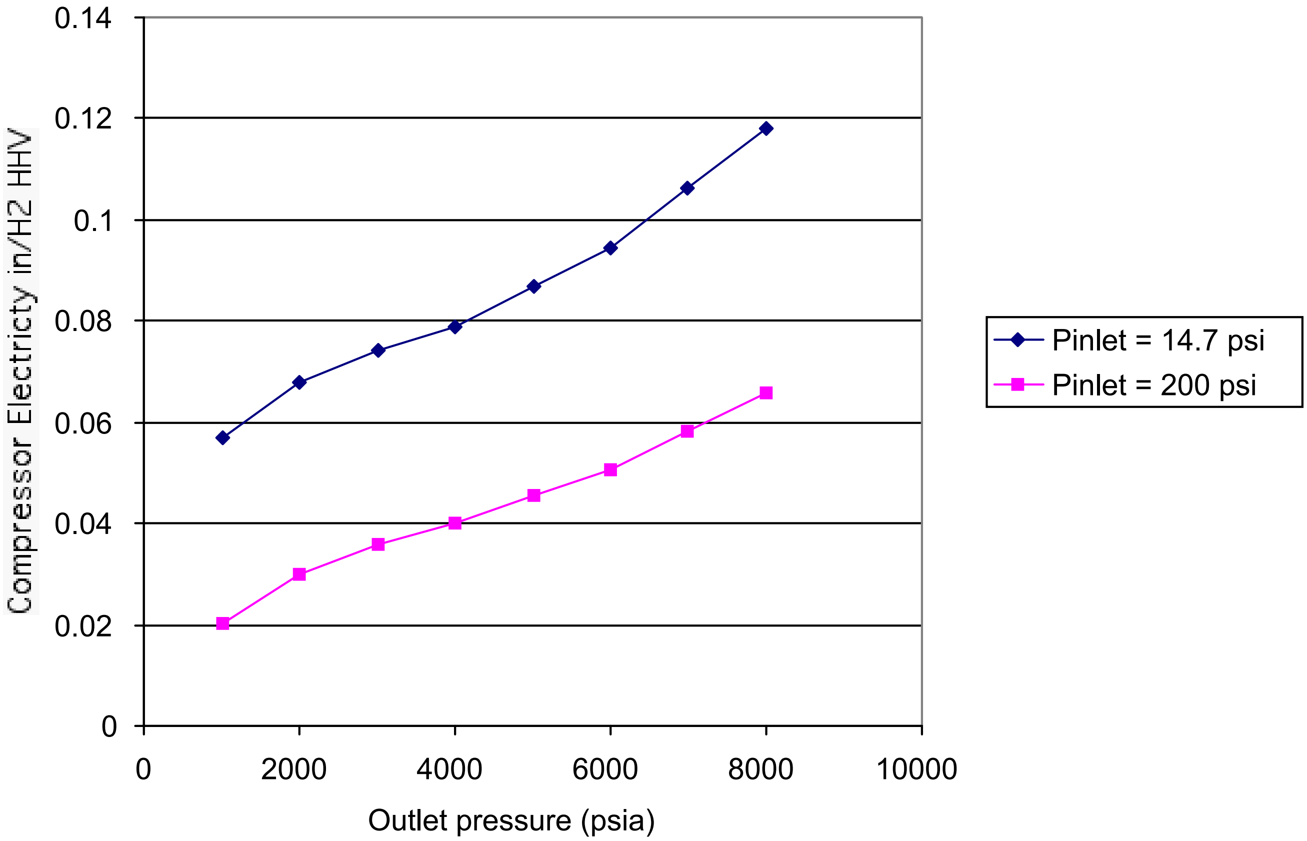


Figure 15.

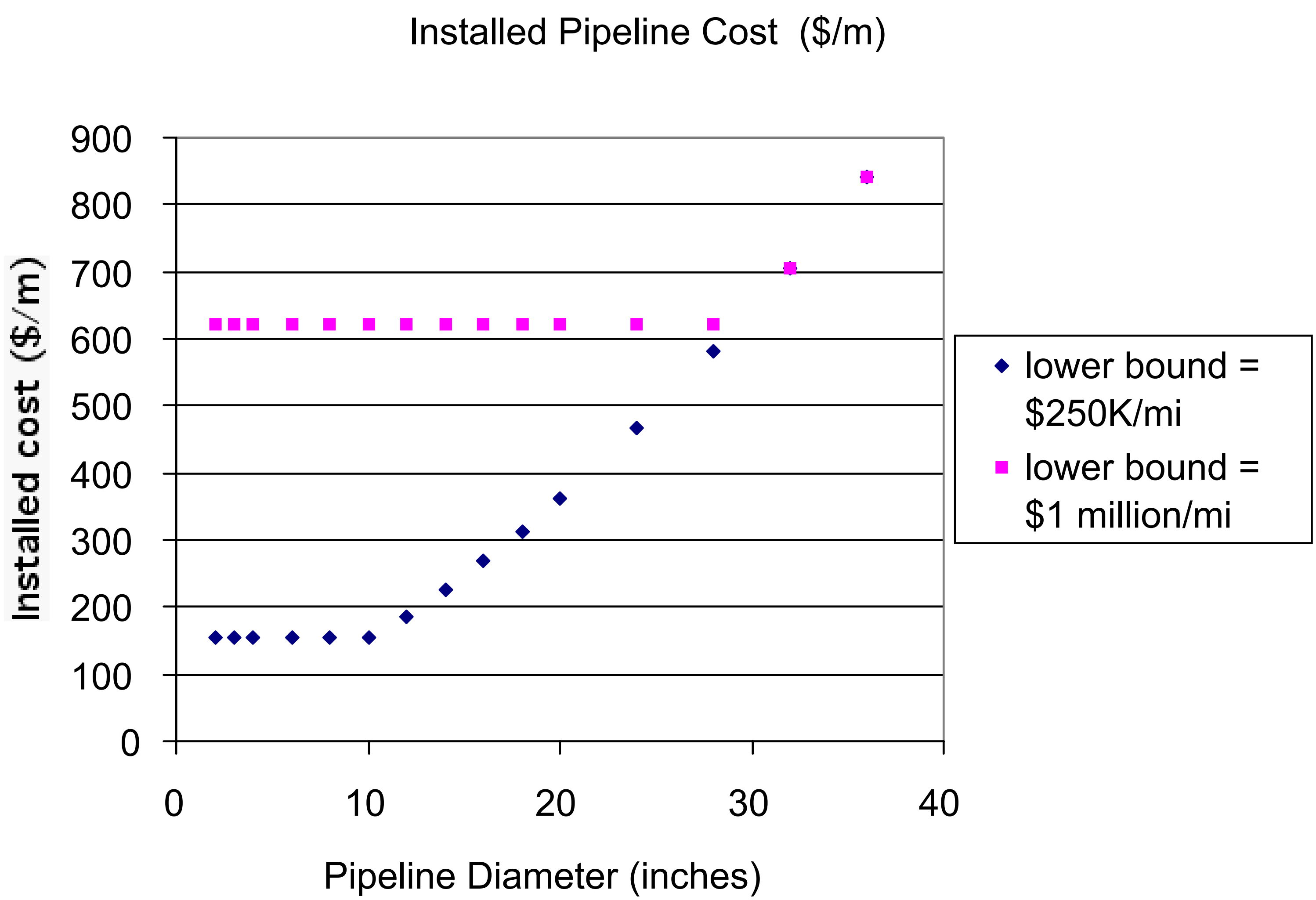

Installed Pipeline Cost ($/m)
900
800
700
600
500
400
300
200
100
0
Installed cost ($/m)
0
10
20
30
40
Pipeline Diameter (inches)
lower bound = $250K/mi
lower bound = $1 million/mi

Figure 15a.

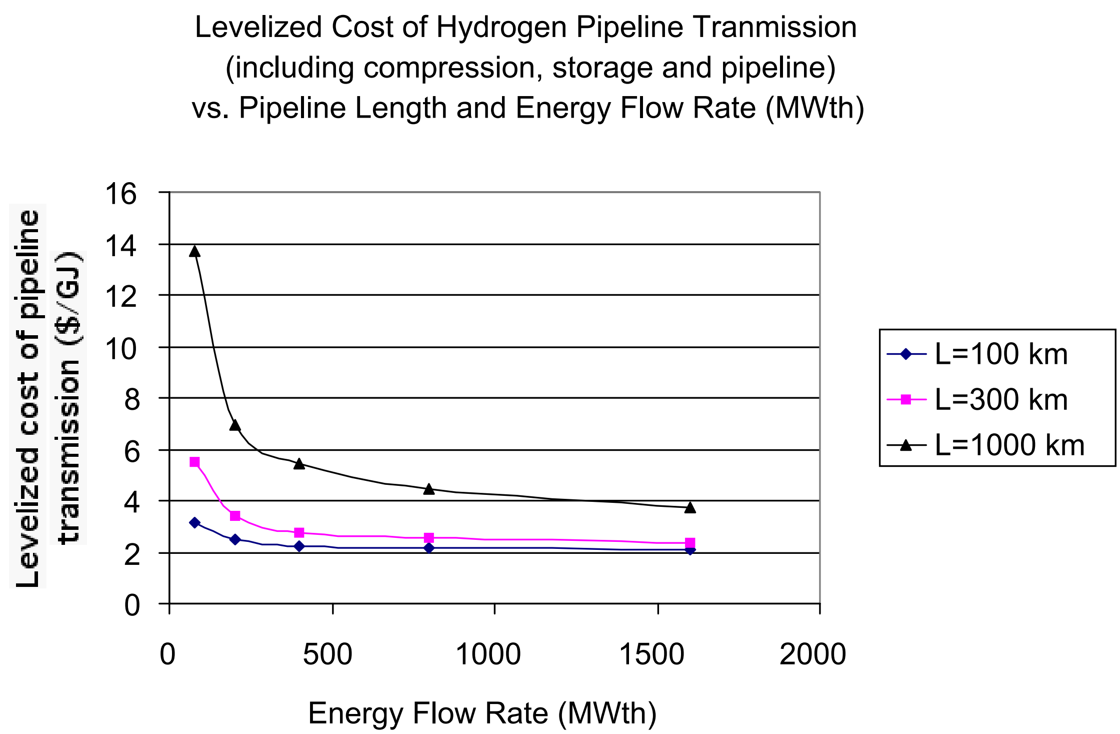
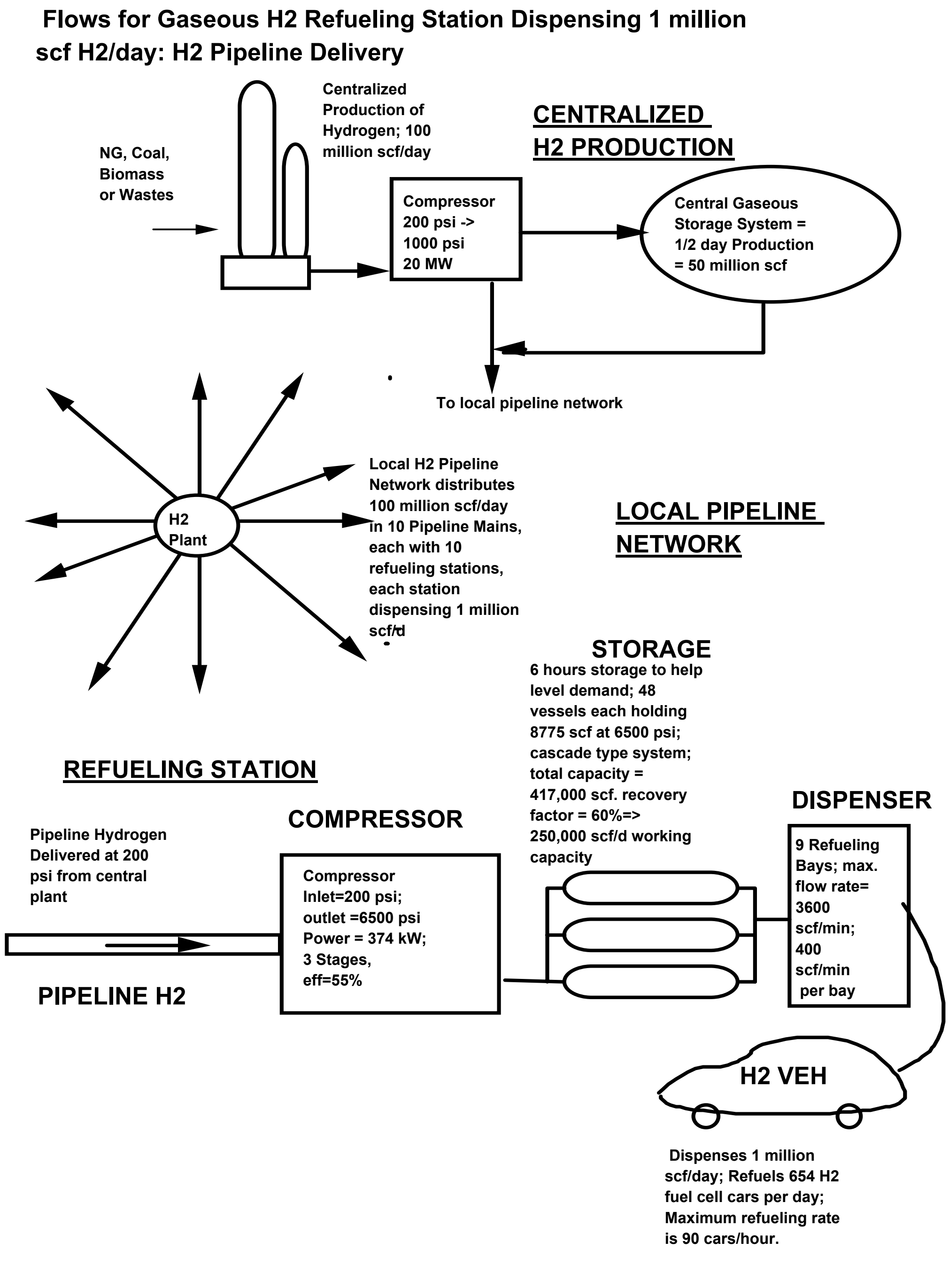

Levelized Cost of Hydrogen Pipeline Tranmission
(including compression, storage and pipeline)
vs. Pipeline Length and Energy Flow Rate (MWth)
Levelized cost of pipeline transmission ($/GJ)
0
2
4
6
8
10
12
14
16
0
500
1000
1500
2000
Energy Flow Rate (MWth)
L=100 km
L=300 km
L=1000 km

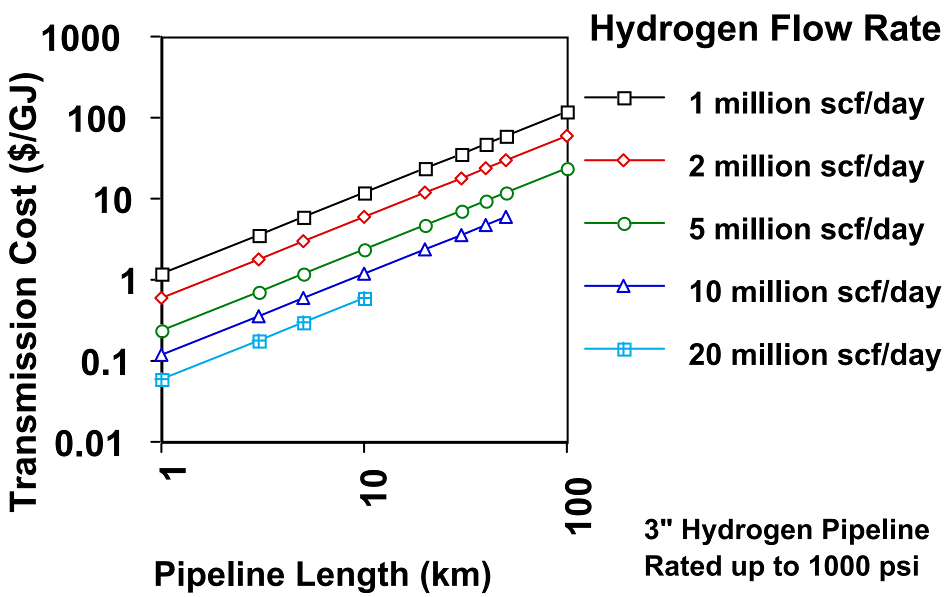
Figure 16



Flows for Gaseous H2 Refueling Station Dispensing 1 million scf H2/day: H2 Pipeline Delivery
NG, Coal, Biomass or Wastes
Centralized Production of Hydrogen; 100 million scf/day
CENTRALIZED H2 PRODUCTION
Compressor 200 psi -> 1000 psi 20 MW
Central Gaseous Storage System = 1/2 day Production = 50 million scf
To local pipeline network
H2 Plant
Local H2 Pipeline Network distributes 100 million scf/day in 10 Pipeline Mains, each with 10 refueling stations, each station dispensing 1 million scf/d
LOCAL PIPELINE NETWORK
STORAGE
6 hours storage to help level demand; 48 vessels each holding 8775 scf at 6500 psi; cascade type system; total capacity = 417,000 scf. recovery factor = 60%=> 250,000 scf/d working capacity
REFUELING STATION
COMPRESSOR
DISPENSER
Pipeline Hydrogen Delivered at 200 psi from central plant
Compressor Inlet=200 psi; outlet =6500 psi Power = 374 kW; 3 Stages, eff=55%
9 Refueling Bays; max. flow rate= 3600 scf/min; 400 scf/min per bay
PIPELINE H2
H2 VEH
Dispenses 1 million scf/day; Refuels 654 H2 fuel cell cars per day; Maximum refueling rate is 90 cars/hour.

Figure 17

Figure A.11. Cost of Hydrogen Pipeline Transmission vs. Pipeline Length and Flow Rate



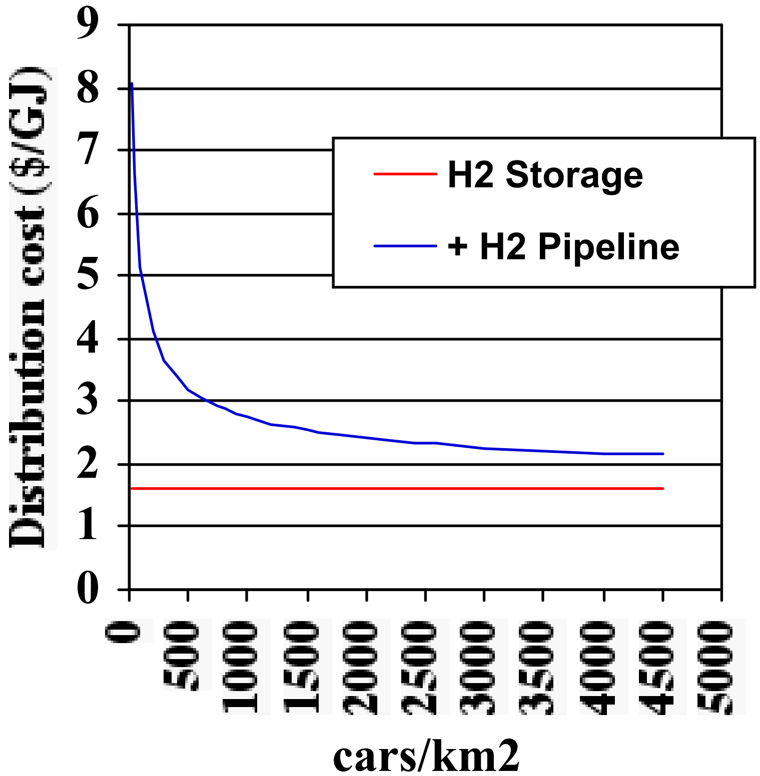
3" Hydrogen Pipeline
Rated up to 1000 psi

Pipeline cost =
$1 million/mile

Inlet Pressure = 1000 psia
Outlet Pressure > 200 psia

1 million scf/day serves a fleet of 9200 Fuel Cell Cars
or 140 Fuel Cell Buses

Figure 18



Distribution cost ($/GJ)
9
8
7
6
5
4
3
2
1
0
H2 Storage
+ H2 Pipeline
0
500
1000
1500
2000
2500
3000
3500
4000
4500
5000
cars/km2

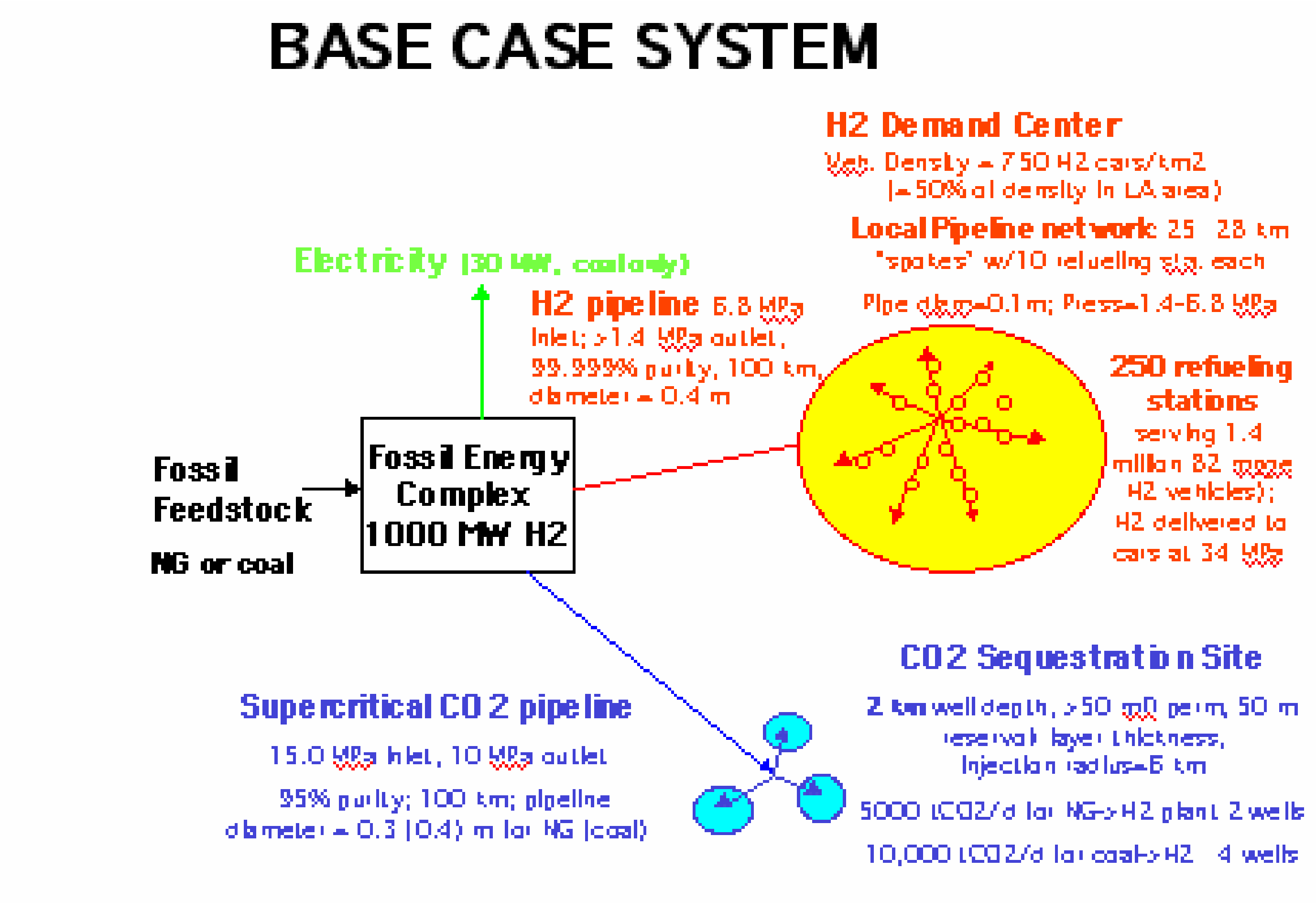

BASE CASE SYSTEM
H2 Demand Center
Veh. Density = 750 H2 cars/km2
(=50% of density in LA area)
Local Pipeline network: 25 28 km
"spokes" w/10 refueling sta. each
Pipe diam=0.1 m; Press=1.4-6.8 MPa
Electricity (30 MW, coal only)
H2 pipeline 6.8 MPa
inlet; >1.4 MPa outlet,
99.999% purity, 100 km,
diameter = 0.4 m
250 refueling
stations
serving 1.4
million 82 mpge
H2 vehicles);
H2 delivered to
cars at 34 MPa
Fossil
Feedstock
NG or coal
Fossil Energy
Complex
1000 MW H2
CO2 Sequestration Site
2 km well depth, >50 mD perm, 50 m
reservoir layer thickness,
Injection radius=6 km
5000 tCO2/d for NG->H2 plant 2 wells
10,000 tCO2/d for coal->H2 4 wells
Supercritical CO2 pipeline
15.0 MPa inlet, 10 MPa outlet
95% purity; 100 km; pipeline
diameter = 0.3 (0.4) m for NG (coal)

Figure 19

Figure 20

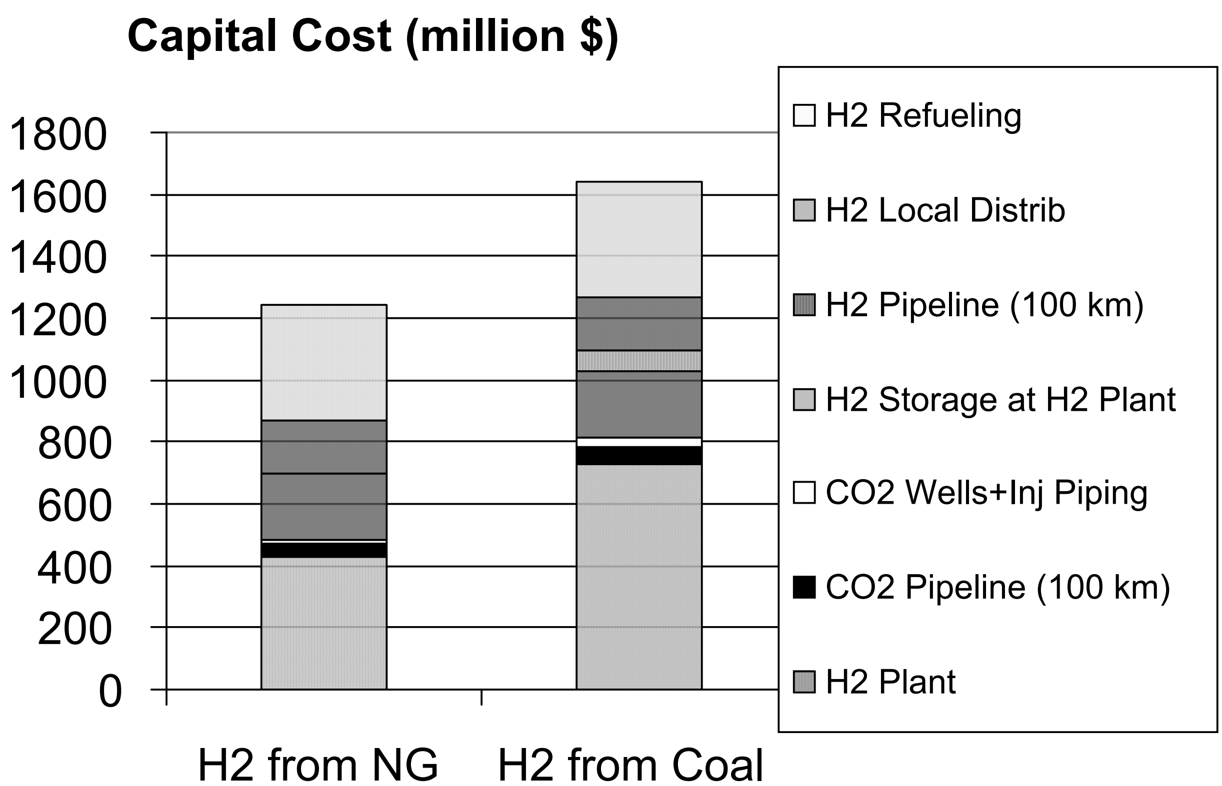
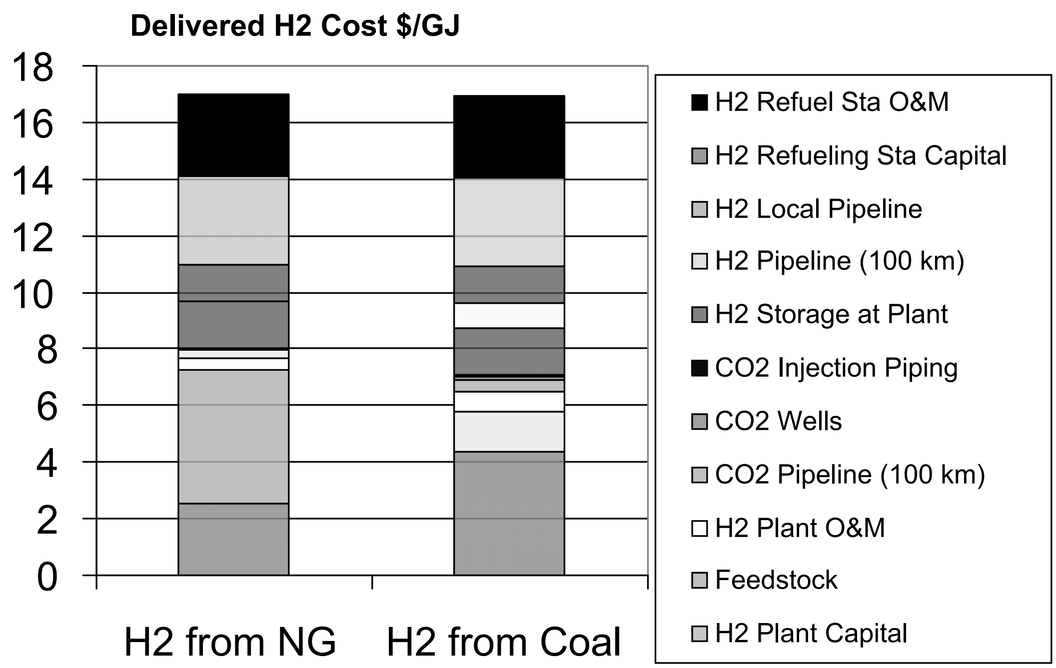

Capital Cost (million $)
1800
1600
1400
1200
1000
800
600
400
200
0
H2 from NG
H2 from Coal
H2 Refueling
H2 Local Distrib
H2 Pipeline (100 km)
H2 Storage at H2 Plant
CO2 Wells+Inj Piping
CO2 Pipeline (100 km)
H2 Plant

Figure 21


Delivered H2 Cost $/GJ
18
16
14
12
10
8
6
4
2
0
H2 from NG
H2 from Coal
H2 Refuel Sta O&M
H2 Refueling Sta Capital
H2 Local Pipeline
H2 Pipeline (100 km)
H2 Storage at Plant
CO2 Injection Piping
CO2 Wells
CO2 Pipeline (100 km)
H2 Plant O&M
Feedstock
H2 Plant Capital