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MODELING INFRASTRUCTURE FOR A FOSSIL HYDROGEN ENERGY SYSTEM WITH CO_2 SEQUESTRATION

Joan M. Ogden
Research Scientist
Princeton Environmental Institute
Princeton University
Princeton, NJ 08544

ABSTRACT

Production of hydrogen (H_2) from fossil fuels 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 pipeline infrastructures: one for distributing H_2 to end-users and one for transmitting CO_2 to disposal sites and securely sequestering it. In this paper we develop a simple technical/economic model of a single fossil energy complex linked by pipelines to a geological CO_2 sequestration site and a H_2 demand center. The goals of the study are to better understand design issues and costs for the total system and to identify the most important factors influencing the sequestration cost of CO_2 and the delivered cost of H_2. For our base case (large flows of H_2 and CO_2; nearby CO_2 storage reservoirs with good characteristics), the most important factors contributing to the delivered cost of H_2 transportation fuel are H_2 production, pipeline distribution and refueling stations. The costs of CO_2 capture and compression at the H_2 plant are significant, but the costs of CO_2 pipeline transmission and storage are relatively small.

INTRODUCTION

Production of H_2 from fossil fuels with capture and sequestration of CO_2 would enable continued widespread use of fossil-derived fuels for applications such as transportation, with near-zero full fuel cycle emissions of both air pollutants and greenhouse gases [1]. A large-scale fossil H_2 system with CO_2 sequestration consists of one or more fossil energy complexes plus two pipeline networks—one for distributing H_2 to end-users (e.g. H_2 vehicles) and one for transmitting CO_2 to storage sites and securely sequestering it.

The performance and economics of the system depend on:

- the design of the central fossil energy conversion plant [scale, feedstock (e.g., 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)];
- the requirements of H_2 end-users (scale, geographic density of H_2 demand, H_2 purity, H_2 pressure);
- the characteristics of the CO_2 sequestration site (storage capacity, permeability, reservoir thickness, location);
- pipeline constraints (e.g., for CO_2 pipelines; moisture content must be low; for H_2 pipelines, materials must be selected to resist embrittlement; for both, availability of rights of way).

Several detailed technical and economic studies have been carried out for various parts of the system, including CO_2 capture from electric power plants [2-4], or H_2 plants [5-8], CO_2 transmission [9] and storage [10], and H_2

infrastructure [11, 12]. However, relatively little work has been done assessing the entire system in an integrated way. This study seeks to understand better the total system design and economics, for the special case of a single large fossil energy complex connected to a geological CO_2 sequestration site and a H_2 demand center (such as a city with a large concentration of H_2 vehicles) [13]. We estimate the delivered cost of H_2 with CO_2 sequestration as a function of fossil energy complex design, pipeline parameters, distance to sequestration site, and CO_2 injection site reservoir parameters. The model developed here can be extended to fossil H_2 energy systems that include multiple fossil energy complexes, H_2 demand centers and CO_2 sequestration sites.

MODEL OF A FOSSIL HYDROGEN ENERGY SYSTEM WITH CO_2 SEQUESTRATION

Overview of the System 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 1000 MW of H_2, higher heating value basis (25.4 tonnes H_2/hr). . At an assumed 80% capacity factor, annual H_2 production is 25.2 million GJ (178,000 tonnes)—enough to fuel 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). To find levelized costs, we assume a 15% annual capital charge rate and an annual non-fuel O&M charge of 4% of the installed capital cost. Feedstock costs are USDOE projections for 2020 costs to electric utilities: \$3.75/GJ for natural gas and \$0.95/GJ for coal [14]. Costs are in constant 2001 US dollars.

Fossil Energy Complexes Producing Hydrogen and Electricity The assumed performance and cost characteristics of 1000 MW H_2 plants are summarized in Table 1. The coal-based and natural-gas-based energy complexes are taken from the "Conventional Technology" case in [8] and from [5] respectively. H_2 compression to 6.0 MPa and CO_2 compression to 15 MPa are included in all H_2 plant designs. From Table 1, we see that coal to H_2 plants have larger capital costs but lower feedstock costs, so that the levelized H_2 production cost is somewhat lower than for natural gas. The coal to H_2 plant produces about twice as much CO_2 as the natural gas to H_2 plant.

TABLE 1. 1000 MW FOSSIL H_2 PRODUCTION PLANTS W/CO_2 CAPTURE AND COMPRESSION

	H_2 from Natural Gas [4]	**H_2 from Coal [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

These results can be extended to smaller complexes, using appropriate scaling factors [13]. At 250 MW the H_2 production cost is about \$2/GJ higher than at 1000 MW [13].

Hydrogen Pipeline Distribution Costs for H_2 distribution and refueling systems are shown in Table 2. 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 [15,16], the optimal 100 km H_2 transmission pipeline diameter is 0.29 m, and the associated cost is \$0.35/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 [15] and recent industry estimates [17].) For an alternative H_2 energy flow rate Q and pipeline length L, the cost can be estimated as (\$0.35/GJ) x $(Q/1000\ MW)^{-0.5}$ x $(L/100\ km)^{1.25}$.

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 [11]. 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.

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 [11]. (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 [12].)

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 2. 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)		0.35
Citygate H_2 Booster compressor (coal only)		0.55
H_2 Local Distribution Pipelines	1.29	1.29
Sub-total H_2 Distribution (excuding.refueling station).	*2.92*	*3.27*
H_2 Refueling Station	6.06	6.06
Total	*8.98*	*9.88*

Hydrogen Refueling Stations H_2 is dispensed to vehicles at refueling stations as a high-pressure gas (at 34 MPa) for storage in onboard cylinders. 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 2) [11] 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 onboard H_2 storage is not included. Development of a new H_2 storage technology that requires less capital and energy input than compressed gas could reduce refueling station costs.

CO_2 Pipeline To model supercritical CO_2 pipelines, we use pipeline flow equations developed in [16] and [18]. Published estimates of capital costs for CO_2 pipelines vary over more than a factor of two above and below the midrange value used here [6, 9, 10, 13, 20]. Local terrain, construction costs and rights of way are all important variables in determining the actual installed pipeline cost. 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 [13]:

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

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

The levelized cost of CO_2 pipeline transmission 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. It is assumed that booster compressors are not needed for this 100 km pipeline. For transmission of more than 100 km, boosters might be needed.

CO_2 Sequestration 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 [2]. Using a standard equation for flow into an injection well [2], 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 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 [2]:

$$\text{Capital (\$/well)} = \$1.56 \text{ million} \times \text{well depth (km)} + \$1.25 \text{ million.}$$

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

TABLE 3. CO_2 PIPELINE TRANSMISSION AND STORAGE SYSTEM

	H_2 from natural gas	**H_2 from coal**
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 $)		
CO_2 100 km Pipeline	40.5	55.7
CO_2 Injection Wells	8.8	17.5
CO_2 Injection Site Piping	3.2	9.2
Total CO_2 Pipeline Transmission and Storage System	*52.5*	*82.4*
Levelized Cost of CO_2 Disposal ($/t$CO_2$)		
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**

[1], but assuming that the minimum cost is \$155,000/km (\$250,000/mile) [11]. 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).]

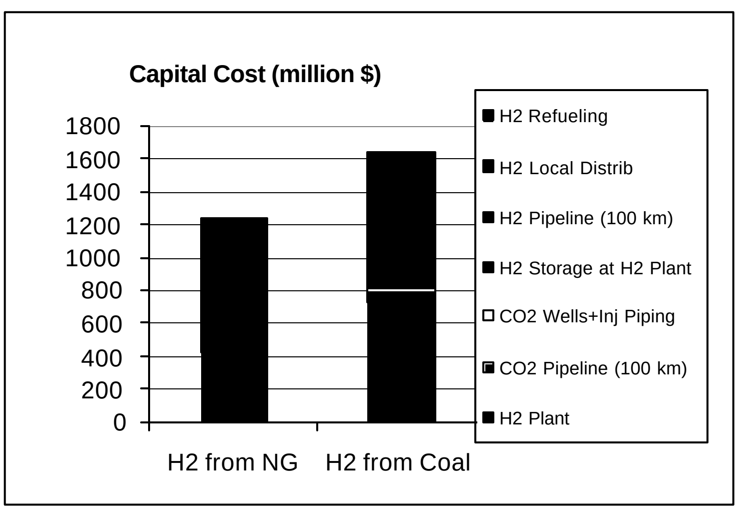
The total levelized cost of CO_2 pipeline transmission and storage is shown in Table 3. Per tonne of CO_2, the cost of CO_2 disposal is higher for natural gas, but because the coal plant produces about twice as much CO_2 as the natural gas H_2 plant, the contribution to the levelized cost of H_2 (\$/GJ) is higher for coal. However, the sum of the costs for CO_2 capture (\$1.33/GJ H_2 for natural gas [19] and \$0.95/GJ H_2 for coal [8]) 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.

SUMMARY OF RESULTS FOR SYSTEM CAPITAL COST AND DELIVERED HYDROGEN COST

In Figure 1, 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. 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 [5, 8, 13].

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 1). 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 [11].



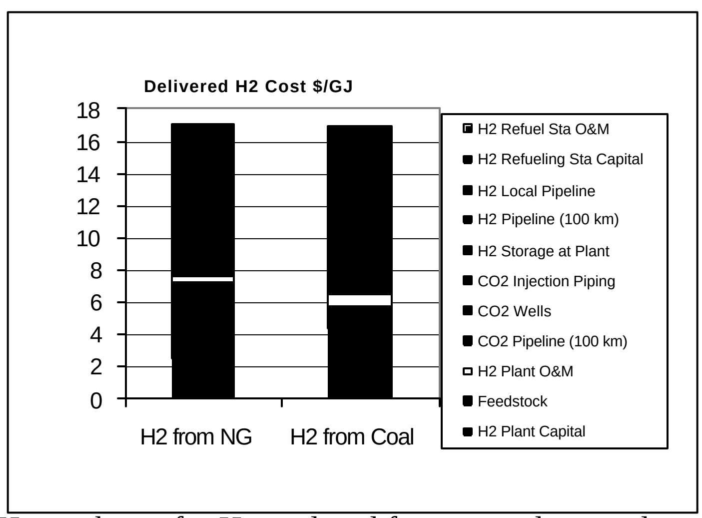


Figure 1. The system capital cost and the delivered cost of H_2 are shown for H_2 produced from natural gas and coal with CO_2 capture, transmission and storage, and H_2 pipeline distribution and refueling. The H_2 plant capacity is 1000 MW, which is large enough to support 1.4 million H_2 fuel cell cars.

CONCLUSIONS

Using a technical/economic model of large-scale fossil H_2 energy systems with CO_2 sequestration, 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.

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