CONFERENCE PROCEEDINGS

Conceptual Design of a Fossil Hydrogen Infrastructure with Capture and Sequestration of Carbon Dioxide: Case Study in Ohio

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FOURTH ANNUAL CONFERENCE ON CARBON CAPTURE AND SEQUESTRATION DOE/NETL
May 2-5, 2005

Abstract

Researchers at the University of California, Davis, in support of the Department of Energy's Fossil Energy programs, are developing engineering/economic/geographic models of fossil hydrogen energy systems with carbon capture and sequestration. In this paper, we present initial results from an ongoing assessment of alternative transition strategies from today's energy system toward widespread use of H_2 from fossil fuels as an energy carrier with capture and sequestration of CO_2. This study is coordinated with the National Energy Technology Laboratory Carbon Sequestration program and hydrogen modeling efforts at UC Davis and within the USDOE such as H2A. In the future, we plan to utilize data on CO_2 sequestration sites from the NATCARB program, and the Regional Sequestration Partnerships.

Our model for the design and economics of a fossil H_2 energy system with CO_2 sequestration considers a number of factors including:

- Cost and performance of component technologies making up the system (e.g. fossil energy complex including CO_2 capture technology and co-production of hydrogen and electricity, CO_2 pipelines and hydrogen storage, distribution and refueling stations).
- The location and characteristics of the CO_2 sequestration site (storage capacity, permeability, reservoir thickness),
- The location, type, size and geographic density of the H_2 demand.
- Cost, location and availability of primary resources for H_2 production such as coal or natural gas.
- Location of existing energy infrastructure and rights of way.

We have developed techniques for studying regional H_2 and CO_2 infrastructure development and transition strategies, based on use of Geographic Information System (GIS) data and network optimization techniques. GIS facilitates this analysis by allowing one to use spatially-referenced data, such as existing power plants, coal resources, population distribution, existing rights of way, and CO_2 sequestration sites, to calculate the location and magnitude of hydrogen demand and optimize the placement of production facilities and pipeline networks for transporting hydrogen and CO_2.

We have applied the model to a regional case study of a coal-based hydrogen economy in Ohio with CO_2 capture and sequestration. The objective is to model the optimal hydrogen infrastructure design for the entire state under different market penetration scenarios, and find the cost of building the system. In the future, we will extend this work to different regions of the US to conduct a national case study, in coordination with the Department of Energy's National Energy Technology Laboratory, NATCARB and the Regional Sequestration Partnerships.

1. Introduction

Hydrogen has been proposed as a future energy carrier that offers several potential benefits in terms of energy supply security and environment. H_2 can be used in fuel cells or engines with high efficiency and zero emissions. H_2 can be produced from a variety of widely available primary sources, including fossil fuels, renewables and nuclear energy, allowing a diversification of transportation fuels away from the current reliance on oil.

A large majority of industrial H_2 today (~95% worldwide) is produced from fossil energy sources. Fossil H_2 with carbon capture and sequestration (CCS) is potentially attractive as a future energy carrier. If H_2

is produced from fossil sources with carbon capture and sequestration, it would be possible to produce and use fuels with near-zero full fuel cycle emissions of greenhouse gases, large reductions in emissions of air pollutants, and essentially zero oil use. A recent study of the "Hydrogen Economy" by the National Academies (NAE 2004) identified the need to develop viable transition strategies, citing this as a key barrier for developing a H_2 as an energy carrier. In this paper, we present initial results from an ongoing assessment of alternative transition strategies from today's energy system toward widespread use of H_2 from fossil fuels as an energy carrier with capture and sequestration of CO_2..

The future use of fossil H_2 with carbon capture and sequestration requires the development of two new infrastructures: one for H_2 supply including H_2 production facilities, a distribution network, and refueling stations, and one for CO_2 disposal infrastructure, including CO_2 compression, pipelines and injection wells. We have developed techniques for studying regional H_2 and CO_2 infrastructure development based on use of Geographic Information System (GIS) data and network optimization techniques. In this paper, the model is applied to a regional case study of a potential coal-based H_2 economy in Ohio with CO_2 capture and sequestration. The objective is to model the optimal H_2 infrastructure design for the entire state under different market penetration scenarios. GIS facilitates this analysis by allowing one to use existing spatially-referenced data, such as population distribution, coal resources, existing infrastructure, and CO_2 sequestration sites, to calculate the location and magnitude of hydrogen demand and optimize the placement of production facilities and pipeline networks for transporting hydrogen and carbon dioxide. Engineering/economic models of the costs and technical performance of infrastructure components are developed to estimate the costs, energy usage and emissions of different hydrogen infrastructure options. The goal of this study is to learn more about the design and costs of a large scale fossil hydrogen infrastructure with CCS and to explore sensitivities to key parameters such as feedstock prices, technology performance, and characteristics of CO_2 sequestration sites. From this we hope to distill "rules of thumb" for low cost regional hydrogen and CO_2 infrastructure development.

2. Hydrogen Supply Scenarios Considered

We consider two possible fossil H_2 supply pathways: 1) centralized production of H_2 using coal gasification and 2) distributed H_2 production from natural gas via steam methane reformation at refueling stations (Figure 1). For centralized H_2 production, it is assumed that H_2 is distributed to users (refueling stations for H_2 vehicles) via a local pipeline distribution network, and CO_2 is captured, compressed, and pipelined to sequestration sites for injection into geological reservoirs. (For distributed H_2 production from natural gas, it is not economically viable to capture and sequester CO_2.) To study how the infrastructure design might change as hydrogen demand grows, we consider two market penetration levels for H_2 vehicles, 10% and 50%. The costs, emissions, and energy efficiency are calculated and compared to determine the lowest cost infrastructure design at each market penetration level.

3. Infrastructure Model Description

3.1 Overview of GIS Database

As a basis for regional infrastructure analysis, we developed a GIS database including the spatial location and characteristics of H_2 demand, potential sites for H_2 infrastructure and possible CO_2 sequestration sites. Several existing GIS datasets were used, including census block population [1], coal power plant data [2], existing pipeline rights-of-way [3], brine well locations [4], and interstate highways [5] (Figure 2). US Census data is used to estimate H_2 demand based on population density. To constrain the H_2 infrastructure analysis, we assume that coal-to-hydrogen

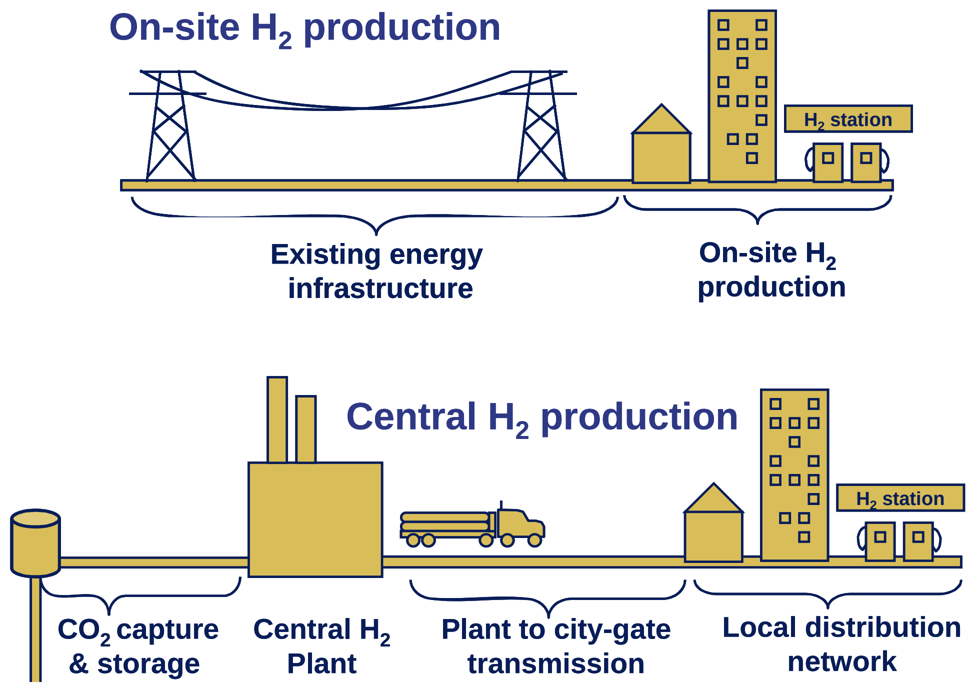


Figure 1. Hydrogen infrastructure: distributed (onsite) and central production pathways

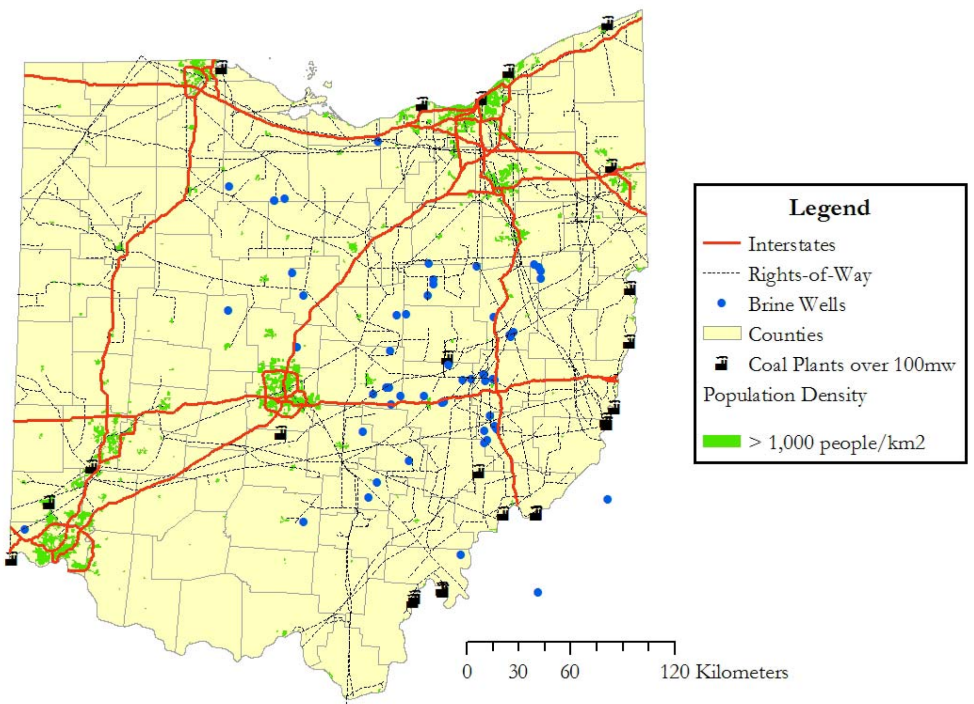


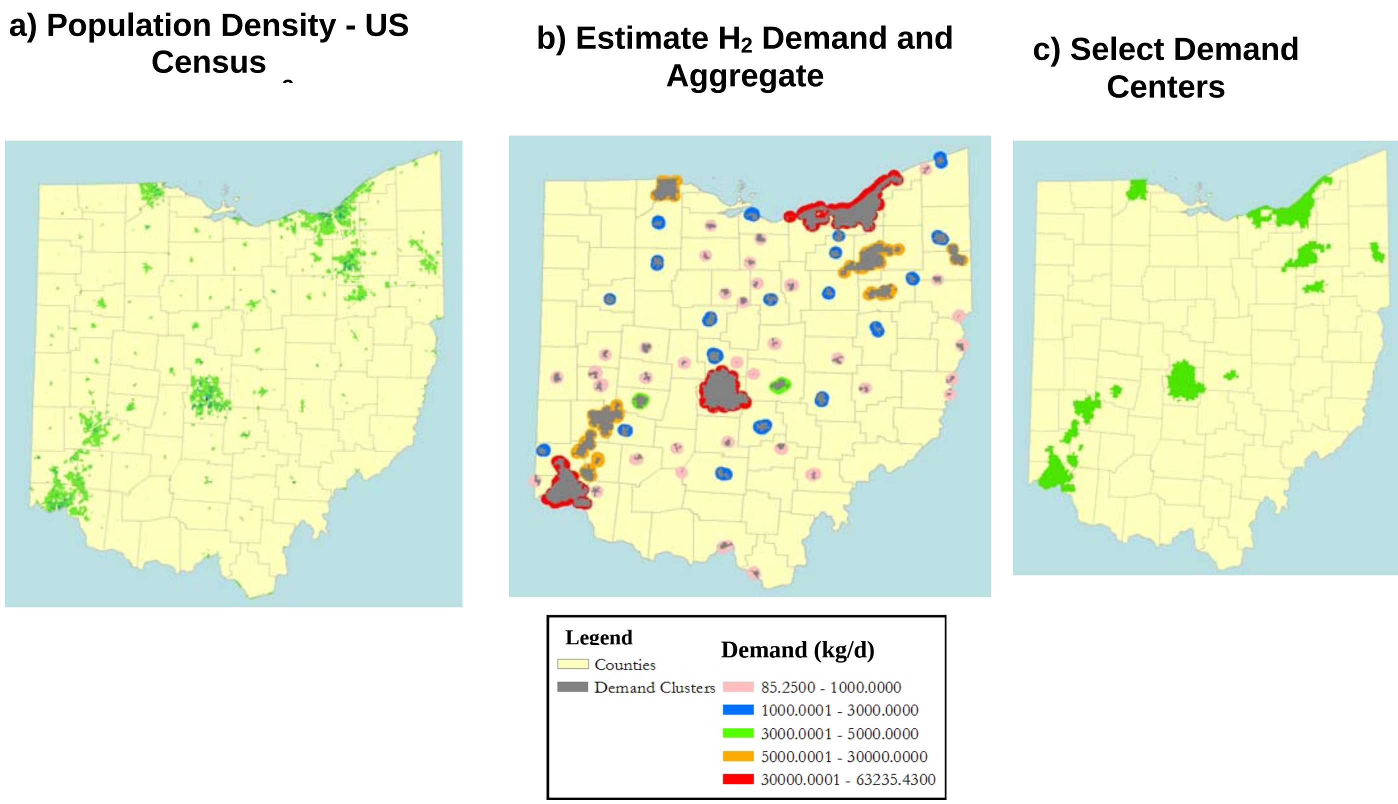
Figure 2. GIS database for Ohio Case Study

facilities will be sited in the same locations as existing coal plants and that hydrogen pipelines will follow existing gas pipeline rights-of-way. Data on location of brine wells accessing deep saline aquifers are used as a proxy for potential reservoirs for CO_2 sequestration. In future work, we plan to incorporate NATCARB data for CO_2 sequestration sites.

3.2. Estimating Hydrogen Demand

The design and cost of a H_2 fuel delivery infrastructure depend on the size, location and geographic density of the H_2 demand. We have developed a preliminary method to model the magnitude and spatial distribution of H_2 demand based on exogenously-specified market penetration levels and GIS data for population density [6]. We use US census-derived population density (Figure 3a), to calculate H_2 demand density. [1] Depending on the analysis year, current or projected population density can be used.

Figure 3: Method for Estimating Spatial Hydrogen Demand in Ohio, H2 vehicle market penetration of 10%



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[1] The hydrogen demand density is calculated based on block level population data from the US 2000 census..

Average hydrogen demand density (kg/d/km^2)
= population density (persons/km^2) x vehicles/person x fraction of H2 vehicles in fleet x H2 use per vehicle (kg/d) .

In this case study, we assume that per-capita vehicle ownership is 0.7 (the statewide average for Ohio) and daily hydrogen use per vehicle is 0.6 kg, corresponding to a 60 mile per gallon equivalent hydrogen fueled car driven 12,000 miles per year [6].)

Buffers are then applied to areas of high demand density to aggregate neighboring census blocks into demand clusters (Figure 3b). The aggregate H_2 demand within each cluster is then calculated and a threshold is applied to retain only the clusters with sufficient H_2 demand to warrant investment ininfrastructure (> 3,000 kg H_2/day) (see Figure 3c). Although this method contains many simplifying assumptions, it provides a means for identifying potentially viable locations or "demand centers" for H_2 infrastructure investment at various market penetration levels.

At 10% market penetration, twelve demand centers are found, as indicated in Figure 4 (right). These demand centers occupy less than 5% of the statewide land area, but capture about 48% of the statewide H_2 demand, which amounts to 253 tonnes H_2 per day. Twenty-three percent of the statewide demand is captured in the three largest cities of Columbus, Cincinnati, and Cleveland. At 50% market penetration, the demand centers increase in size and quantity (Figure 4, right). There are 39 demand centers that capture 74% of the statewide H_2 demand, or approximately 2,000 tonnes of H_2 per day. A single coal facility that could produce 2,000 tonnes of H_2 per day would need the same coal input as a 1,600 MW_e coal-fired steam plant that produces electricity. [2] As 1,600 MW_e is within the size range of existing coal to electricity facilities in Ohio, it is possible that a *single* coal facility could meet the H_2 demand for all the demand clusters statewide, even at high levels of H_2 use (50% market penetration).

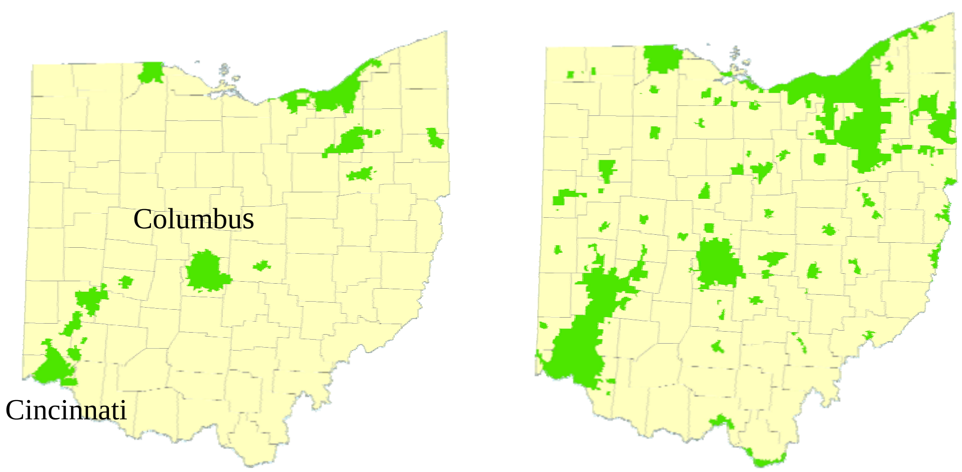

Figure 4: Demand Centers at 10% and 50% Market Penetration of Hydrogen Vehicles

[2]The average coal-fired steam plant produces electricity at about 35% efficiency [2], while a more modern integrated gasification combined cycle (IGCC) plant could produce hydrogen at ~65% efficiency [7,10].

3..3 Designing an Optimized Hydrogen Production and Distribution System
Given the location and quantity of hydrogen demand, the next step is to design and optimize production facilities and distribution networks for delivering hydrogen to the demand centers. We assume that coal to hydrogen plants will be sited in the same locations as today's existing coal plants and will have access to the same amount of coal input.[3]

Given the coal available at each existing plant, we calculate the potential hydrogen production at each facility for two alternative conversion scenarios (Table 2). In both scenarios, it is assumed that the existing coal-fired steam plants are converted to more modern and efficient integrated gasification combined cycle (IGCC) plants and the coal input to the plant is maintained. The first scenario assumes "dedicated" hydrogen production: the existing plant is converted to produce only hydrogen at an efficiency of 65% [7]. In this case, the largest coal facility could produce more than 2,500 tonnes of H_2 per day. If all of the coal facilities statewide were converted to produce only hydrogen, they could produce enough hydrogen to supply approximately 31 million hydrogen vehicles (~18,800 tonnes per day), which is 3.5 times the number of gasoline vehicles currently in Ohio.

The second scenario we "re-power" existing, relatively inefficient coal-to-steam power plants with more efficient IGCC technology. We maintain coal input and electricity production and produce hydrogen with the remaining available coal. The fourth column in Table 2 indicates the efficiencies for producing electricity from coal in each of the existing coal facilities[2]. These values range from 23% to 40%. Assuming that these facilities are converted to IGCC plants, the coal-to-electricity conversion efficiency would increase to about 42%. These gains in efficiency will result in excess coal, which can then be used to produce hydrogen. If all of the coal facilities were re-powered in this manner, they could produce about 1,500 tonnes of H_2 per day, or enough to supply about 30% of the vehicles in the state. The estimation of hydrogen production potential indicates that a *single* coal-to-hydrogen plant could meet statewide demand at both 10% and 50% market penetration if the plant is converted to produce hydrogen exclusively.

Next we identify the location of the coal facility (or facilities) that minimize the length of the intercity pipeline network connecting coal facilities to demand centers. The potential production and transmission infrastructure, including all rights-of-way and coal facilities, is illustrated in Figure 4.

To screen among the large number of potential pipeline routes, GIS spatial analysis tools were to identify the "shortest distance" pathways between the coal facilities and demand centers, as well as between the demand centers themselves. Figure 5 shows the results of this analysis at 10% market penetration, where the red lines indicate the shortest distance pathways. This network represents the portfolio of possible pipeline segments that connect coal facilities and demand centers. For each segment, the distance is calculated and then imported into a matrix in an Excel spreadsheet (Figure 6).

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3 Data for Ohio coal plants is available from the EPA's eGrid power plant database, which provides information such as electricity output, coal input, CO_2 and other important emissions, and plant efficiency[2]. We consider only power plants greater than 100 MW_e in capacity.

Table 2: H_2 Production Potential of Existing Coal Facilities for Two Conversion Scenarios

ID	Plant Name	Scenario 1 - Full Conversion (kg/day)	Plant Efficiency	Scenario 2 - Use excess energy to produce H2 (kg/day)
1	ASHTABULA	138,530	40.14%	2,578
2	AVON LAKE	429,126	34.81%	30,840
3	BAY SHORE	445,308	32.33%	43,042
4	CARDINAL	1,449,802	36.62%	77,933
5	CONESVILLE	1,556,646	33.82%	127,330
6	EASTLAKE	791,977	32.27%	77,023
7	GEN J M GAVIN	2,505,969	32.11%	247,850
8	HAMILTON	51,944	23.22%	9,756
9	KAMMER	568,833	36.75%	29,841
10	KYGER CREEK	1,088,682	35.74%	68,132
11	LAKE SHORE	70,761	23.73%	12,928
12	MIAMI FORT	1,294,250	31.38%	137,507
13	MITCHELL	1,213,062	35.39%	80,196
14	MOUNTAINEER (1301)	1,004,843	35.53%	65,047
15	MUSKINGUM RIVER	1,147,087	35.62%	73,158
16	NILES	188,992	30.64%	21,474
17	O H HUTCHINGS	150,727	28.51%	20,334
18	PHIL SPORN	909,740	36.42%	50,726
19	PICWAY	67,121	30.36%	7,814
20	PLEASANTS	1,053,605	34.50%	79,068
21	R E BURGER	292,972	32.31%	28,389
22	RICHARD GORSUCH	247,459	26.98%	37,164
23	W H SAMMIS	1,861,267	33.06%	166,415
24	WILLOW ISLAND	249,229	28.98%	32,457
	TOTAL	18,777,930	33.87%	1,527,001

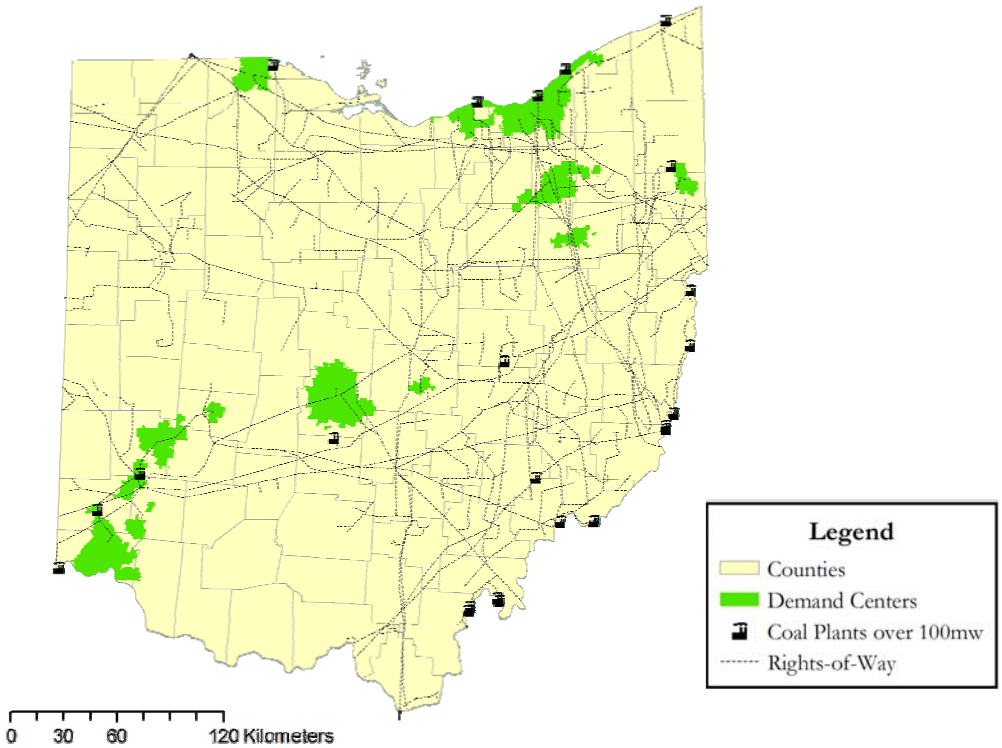


Figure 4: Potential production and transmission infrastructure

In the top portion of the table (Figure 6) are the distances between each coal facility and demand center and the bottom portion includes the distances between the demand centers themselves. A minimal spanning tree optimization algorithm was then applied to identify the optimal (shortest length) pipeline network and production facility for delivering hydrogen to the demand centers. (We make the approximation that the shortest length pipeline network is also the lowest cost, which is defined to be optimal.) The optimized design is imported back into GIS for visualization (Figure 7).

At 10% market penetration (Figure 7), the optimal infrastructure design includes a single coal facility, producing about 250 tonnes of H_2 per day, and twelve demand centers connected by 936 km of transmission pipeline. In addition, there is a CO_2 sequestration system that must be able to handle about 4,500 tonnes of CO_2 per day. A brine well is located immediately adjacent to the optimal production facility so a separate optimization for the CO_2 infrastructure was not necessary. At 50% market penetration, the optimal infrastructure design (Figure 8) includes a single coal facility, producing about 2,000 tonnes of H_2 per day, and thirty-nine demand centers connected by ~ 2,300 km of transmission pipeline. The CO_2 sequestration site is again located adjacent to the production facility and must handle about 34,000 tonnes of CO_2 per day.

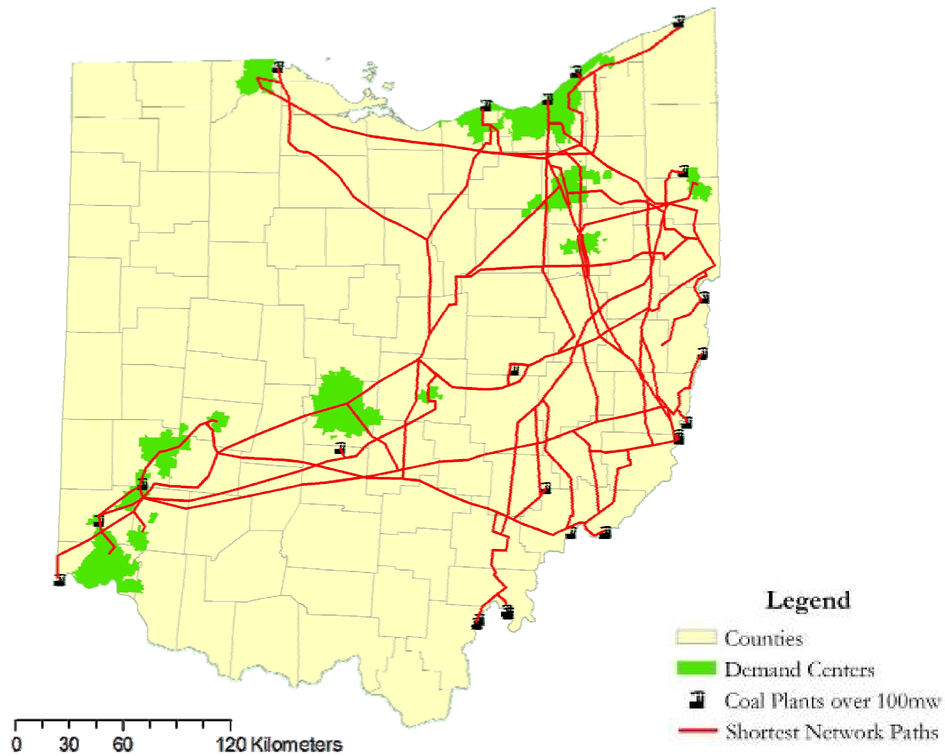


Figure 5: Shortest distance pathways between coal facilities and demand centers (10% market penetration)

Figure 6: Optimization matrix and decision table (10% market penetration)

Distance matrix for all nodes

		Demand Clusters 3	7	13	16	23	43	48	49	52	57	62	65
Coal Plants	101	283	72	171	140	164	288	406	308	428	447	459	481
	102	158	105	152	81	107	181	300	201	321	340	352	374
	103	21	210	257	186	212	226	345	247	367	385	397	420
	104	363	242	186	181	150	218	312	237	334	337	349	372
	105	266	196	162	131	101	70	205	107	227	246	258	280
	106	229	17	129	90	114	234	353	254	374	393	405	427
	107	406	339	304	274	243	194	258	189	280	284	296	318
	108	405	394	412	350	337	204	89	156	54	25	40	22
	109	338	219	163	156	125	193	280	205	301	305	317	339
	110	409	341	306	276	246	196	260	192	282	286	298	320
	111	192	67	117	58	84	198	317	218	338	357	369	391
	112	445	433	452	390	377	244	134	196	99	71	73	55
	113	337	218	162	155	123	192	278	203	300	304	316	338
	114	397	329	295	264	234	185	249	180	270	274	286	308
	115	358	251	216	186	155	146	210	141	232	235	248	270
	116	262	114	49	82	83	229	357	259	379	397	410	432
	117	385	373	392	330	317	184	57	136	22	6.2	31	53
	118	397	329	295	264	234	185	249	180	270	274	286	308
	119	285	274	292	230	217	73	99	52	121	126	138	160
	120	390	291	242	226	196	178	242	173	263	267	279	302
	121	336	215	159	154	123	191	285	210	306	310	322	344
	122	366	272	235	207	176	154	218	149	240	243	256	278
	123	310	162	98	126	122	207	343	245	365	380	392	414
	124	390	291	242	226	195	177	241	172	263	267	279	301
Demand Clusters	3	0	212	259	188	214	229	347	249	369	388	400	422
	7	212	0	111	73	97	217	336	237	357	376	388	410
	13	259	111	0	79	80	226	354	256	376	394	406	429
	16	188	73	79	0	32	174	292	194	314	332	344	367
	23	214	97	80	32	0	161	279	181	301	320	332	354
	43	229	217	226	174	161	0	160	70	182	187	199	221
	48	347	336	354	292	279	160	0	98	35	64	89	111
	49	249	237	256	194	181	70	98	0	120	139	151	173
	52	369	357	376	314	301	182	35	120	0	28	53	76
	57	388	376	394	332	320	187	64	139	28	0	34	47
	62	400	388	406	344	332	199	89	151	53	34	0	50
	65	422	410	429	367	354	221	111	173	76	47	50	0

Decision table

		Demand Clusters 3	7	13	16	23	43	48	49	52	57	62	65
Coal Plant	105	0	0	0	0	**1**	**1**	0	0	0	0	0	0
Demand Clusters	3	0	0	0	0	0	0	0	0	0	0	0	0
	7	0	0	0	0	0	0	0	0	0	0	0	0
	13	0	0	0	0	0	0	0	0	0	0	0	0
	16	**1**	**1**	**1**	0	0	0	0	0	0	0	0	0
	23	0	0	0	**1**	0	0	0	0	0	0	0	0
	43	0	0	0	0	0	0	0	**1**	0	0	0	0
	48	0	0	0	0	0	0	0	0	**1**	0	0	0
	49	0	0	0	0	0	0	**1**	0	0	0	0	0
	52	0	0	0	0	0	0	0	0	0	**1**	0	0
	57	0	0	0	0	0	0	0	0	0	0	**1**	**1**
	62	0	0	0	0	0	0	0	0	0	0	0	0
	65	0	0	0	0	0	0	0	0	0	0	0	0

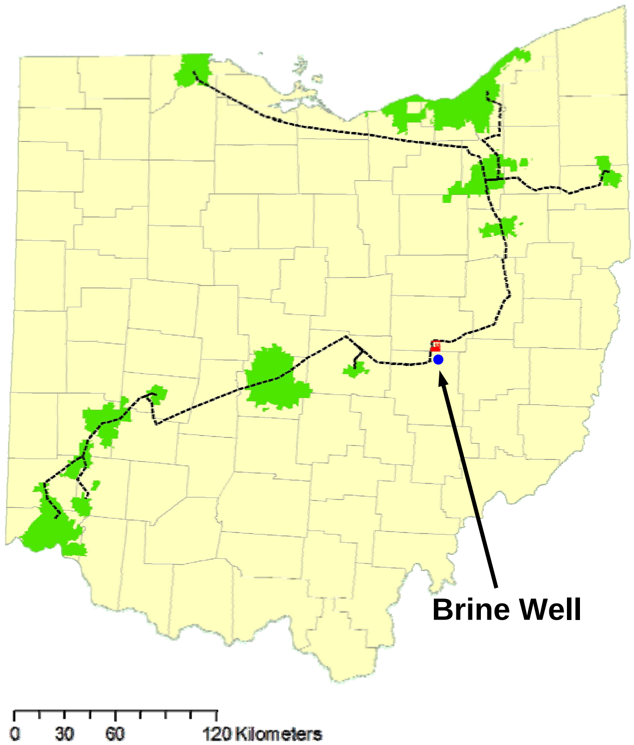
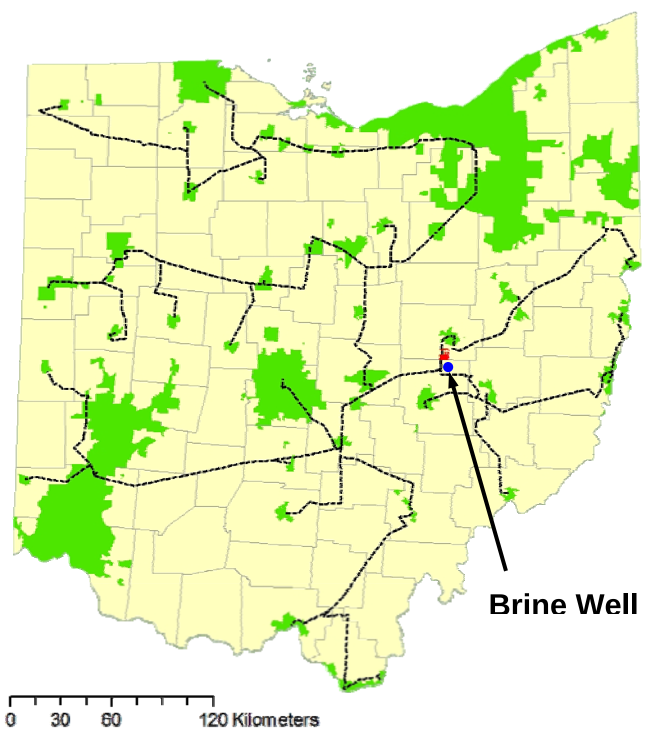


Figure 7: Optimal infrastructure design at 10% market penetration.
Figure 8: Optimal infrastructure design at 50% market penetration



3.4. Intracity Distribution and Station Siting

Given the location and quantity of demand, the location and production capacity of the coal facility, and the location of the hydrogen pipelines, the next step is to identify the infrastructure required for delivering hydrogen to consumers within the demand center boundaries. An idealized city model was used to simplify the estimation of the distribution pipeline length and number of refueling stations [8]. This model assumes that each demand center is represented by a circle of equivalent area (Figure 9a). Within this circle, the refueling stations are arranged along concentric rings and connected by pipelines (Figure 9b). As a result of this simplification, the distribution pipeline length can be estimated from the demand center area and the number of refueling stations.

At 10% market penetration, 147 hydrogen refueling stations are required within the statewide demand centers. At 50% market penetration, 1,117 hydrogen stations are required. These stations deliver an average of 1,800 kg H_2 per day. Given the number of stations and area associated with each demand center, the intracity pipeline distance is estimated. At 10% market penetration, approximately 1,300 km of intracity pipeline is required statewide and the 50% market penetration scenario requires about 5,300 km.

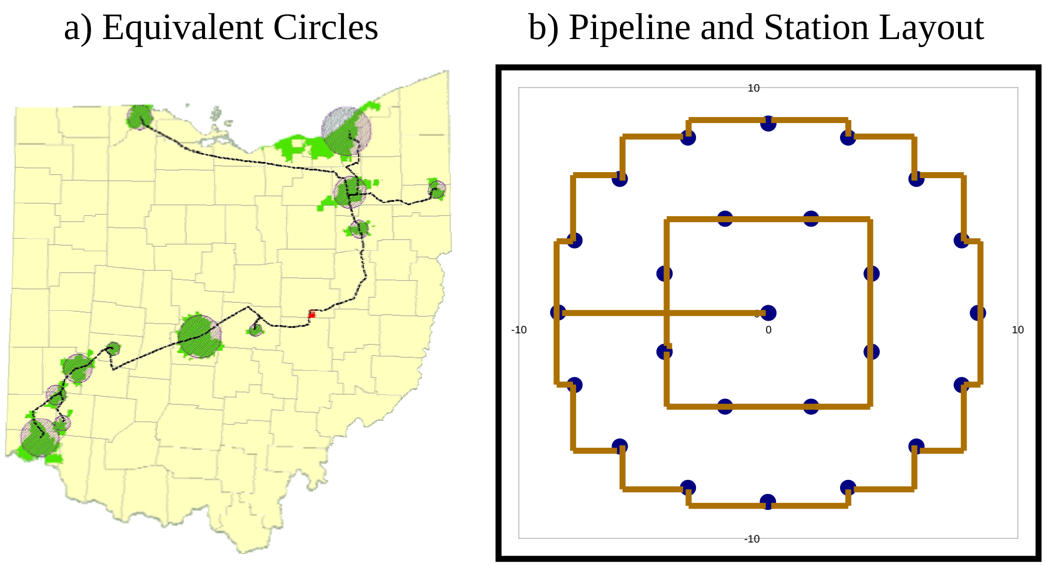


Figure 9: Idealized city model

3.5. Intercity Station Siting

The final component of regional infrastructure design is the siting of intercity stations. These stations are located along interstate highways, so that hydrogen vehicle owners can travel reliably between cities. Potential intercity station sites are identified by selecting all major intersections[4] that involve interstate highways and are within five kilometers of an intercity demand cluster. Ten stations were selected from

[4] Major intersections are defined as those involving interstate, US, and State highways as defined by the Ohio Department of Transportation.

possible sites. The daily hydrogen demand at these sites is estimated by combining the local and intercity traveler demands. We assume that the hydrogen will be produced onsite using natural gas reformation (Figure 10).

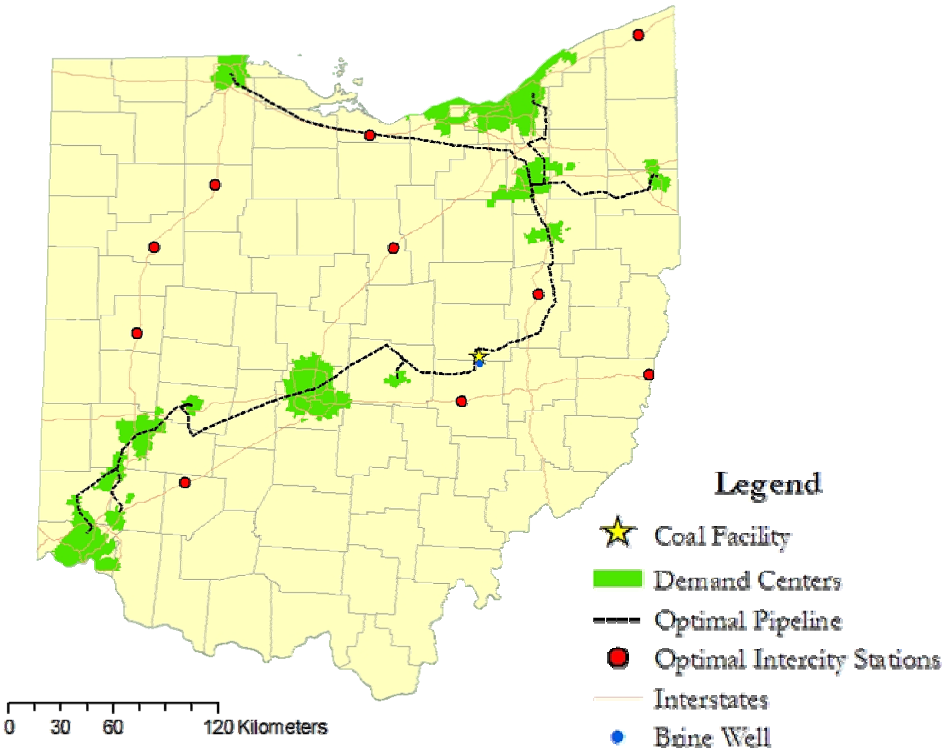


Figure 10: Optimal intercity stations and infrastructure design at 10% market penetration

3.6. Engineering and Economic Models

Once the optimal infrastructure design has been determined, engineering and economic models for each of the infrastructure components are used to determine the cost and technical performance of the system. The models encompass the range of processes and equipment necessary for hydrogen production, transport and distribution, and dispensing as well as sequestration of carbon dioxide.

3.6.1. Central Plant Hydrogen Production

Hydrogen production is modeled for a large coal gasification plant with electricity co-production and carbon capture based upon detailed process designs and modeling from Kreutz et al [7, 10]. The capacity of each plant is constrained by the location and coal input of the existing coal steam power plant as detailed in the EPA eGrid database[2]. The production plants are designed to maximize the hydrogen output (~97% of energy output) with minor electricity co-production (~3%) to provide for electrical requirements (such as H_2 and CO_2 compression). The coal-to-hydrogen energy conversion efficiency is assumed to be 65%. Based upon the demand, we calculated the size of the gasification plant, and its cost using scaling factors for process equipment [7, 10].

3.6.2. CO_2 Sequestration

In the plant design chosen, 92% of the CO_2 is captured and sequestered while 8% is emitted to the atmosphere [7, 10-12]. Once CO_2 has been captured at the central hydrogen plant, it must be dehydrated and compressed to a supercritical state and transported via pipeline to the underground sequestration site. CO2 is compressed to supercritical pressure (15 MPa) for pipeline transmission. CO_2 pipeline costs and technical performance are estimated based upon system designs studied at the Princeton University CMI[5] program [13]. Pipeline costs are based upon a power law function for flowrate and length[14]. Finally, the CO_2 must be injected into an underground geological formation such as a deep saline aquifer. Since we do not currently have accurate data to characterize the injection sites (capacity, depth, permeability, and pressures), we assumed injection costs based upon some generic values associated with large reservoirs [13]. Each well is assumed to be capable of handling up to 2,500 tonnes of CO_2 per day.

3.6.3. Hydrogen Transmission and Distribution Pipelines

Pipelines are used for the transmission of hydrogen from the central hydrogen production plant to each of the demand clusters as well as distribution within each of the demand clusters to the network of refueling stations located within those clusters. Detailed steady-state pipe flow equations are used to model the pressure drop and diameter tradeoffs for hydrogen as well as determining material requirements and overall pipeline costs [13, 15]. Costs are related to a number of factors including pipeline flowrate, required outlet pressure, and length.

3.6.4. Refueling Stations

For onsite hydrogen production from natural gas, the refueling station includes all of the equipment and costs associated with hydrogen production via SMR, compression, storage and dispensing. A refueling station cost model is used to estimate the costs of stations for both on-site production and delivered hydrogen [16]. The stations are assumed to have a maximum size of 1,800 kg/day and small modular reformers can be added in 600 kg/day increments. We use projected costs for small SMR units based on future mass production ($400,000 for a 600 kg/day capacity) [17].

For centrally produced hydrogen from coal that is distributed via pipeline, the stations include compressors, hydrogen storage and dispensing. High-pressure gaseous storage costs are assumed to be $400/kg (H2A forecourt costs [17]). Storage requirements for these station types will differ because of the difference between the maximum throughput of pipelines versus an onsite SMR. It is assumed that a station with an onsite SMR would require approximately 75% of a day's production in the form of storage, while stations with pipeline delivery can reduce the storage requirement to 25%.

4. Results

Given the optimized infrastructure design for each scenario, the cost, overall energy efficiency, and CO_2 emissions are evaluated and compared. At 10% market penetration, the optimal infrastructure design for the centralized coal-to-hydrogen scenario is illustrated in Figure 11. This design serves approximately 420,000 hydrogen vehicles and includes one coal-to-hydrogen plant that produces 253 tonnes H_2 per day and 936 kilometers of intercity transmission pipeline that connect the coal facility to the twelve demand centers. Within the demand centers, there are 1,344 kilometers of intracity distribution pipeline and 147 intracity refueling stations that deliver hydrogen to consumers. In addition, ten intercity refueling stations provide connectivity between demand centers and one CO_2 sequestration site handles the approximately 4,500 tonnes CO_2 that is generated from the coal facility daily.

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[5] Carbon Mitigation Initiative

At 50% market penetration, the optimal infrastructure design serves about 3.3 million hydrogen vehicles and includes one coal-to-hydrogen plant that produces 1,975 tonnes H_2 per day (see Figure 8). This facility is linked to the 39 demand centers by 2,286 kilometers of intercity pipeline while 5,260 kilometers of intracity pipeline and 1,117 refueling stations deliver hydrogen to consumers within the demand centers. Finally, there is a single CO_2 sequestration site that handles about 35,000 tonnes CO_2 per day. Intercity stations are not necessary at 50% market penetration since demand centers occur along the interstates.

	Centralized Coal to Hydrogen w/ CCS		Onsite H2 production from Natural Gas @$7/MMBTU	
	10% Market Penetration	50% Market Penetration	10% Market Penetration	50% Market Penetration
# Demand centers	12	39	12	39
Number of Vehicles	421,197	3,291,791	421,197	3,291,791
# Refueling Stations	147	1117	147	1117
Intercity H2 pipeline (km)	936	2286	-	-
Intracity H2 pipeline (km)	1344	5260	-	-
Coal Plant (tonne/d)	253	1975	-	-
CO_2 sequestered (tonne/d)	4500	35,000	-	-
CAPITAL COST (million $)				
H_2 Production	351	1,926	-	-
H_2 Compressors	30	192	-	-
H2 Transmission Pipelines	358	1,068	-	-
H2 Distribution (Intracity) Pipelines	439	2,493	-	-
Refueling Stations	164	1,246	499	4,100
CO_2 Sequestration (CO_2 compressor, piping, wells)	55	268	-	-
Intercity Stations	37	-	$37	-
TOTAL CAPITAL	**1,434**	**7,192**	**536**	**4,100**
Infrastructure Cost per Vehicle $/Veh.	$3,404	$2,185	$1,273	$1,245
Levelized Delivered Cost of H_2 ($/kg)	3.54	2.57	2.47	2.47

Table 3: Capital and Installation Costs ($ Millions)

Table 3 summarized the results for each scenario, and lists the capital and installation costs associated with each of the infrastructure components for the four design scenarios. In addition, Figure 12 compares the four options based on the levelized cost of hydrogen (delivered), which includes O&M and feedstock costs. Based on these graphs, it is apparent that the onsite scenario ($2.47/kg) results in a significantly lower levelized cost of hydrogen than the centralized scenario ($3.54/kg) at 10% market penetration. When market penetration is increased to 50%, the production and distribution costs associated with centralized production benefit greatly from economies of scale and result in a significant decrease in the levelized cost to $2.57/kg. However, onsite production still remains slightly cheaper at $2.47/kg.

If policymakers were to institute a $50 per tonne carbon tax, the levelized cost associated with onsite production would increase by about $0.17 to $2.64 per kg, since sequestration of CO_2 is not performed in this scenario, while the centralized coal scenario with sequestration would only increase by $0.06 to about $2.63 per kg. With a $50/tonne carbon tax, at 50% market penetration, the centralized coal scenario becomes economically favorable.

The result is also sensitive to the assumed natural gas price. If the natural gas feedstock price were to increase by as little as 10% above the assumed commercial price of $7/MMBTU , the coal scenario would yield lower costs. As the price of coal feedstock is unlikely to change significantly in the near future, the coal scenario is less sensitive than the onsite (natural gas) scenario to fluctuations in future energy prices. (The sensitivity of delivered hydrogen costs to coal and natural gas prices is shown in Figure 12, for hydrogen plants producing 600 tonnes H2 per day. For this example, hydrogen production in central plants is generally lower cost than onsite natural gas, unless natural gas prices are less than about $5/MMBTU.)

CO_2 emissions are evaluated for several well-to-wheels scenarios, including coal-based hydrogen with and without sequestration, onsite production of hydrogen using natural gas reformation, and the existing gasoline-based transportation system. For the hydrogen-based scenarios, it is assumed that fuel cell vehicles (with fuel economy equivalent to ~ 60 mpg gasoline) are used, whereas the gasoline-based scenario assumes advanced internal combustion engine (ICE) vehicles (with fuel economy equivalent to ~ 40 mpg gasoline). For the coal with sequestration scenario, it is assumed that 92% of the CO_2 is captured at the plant and the electricity used in the scenario is not decarbonized, but has emissions consistent with the standard Ohio grid mix.

The well-to-wheels CO_2 emissions associated with each scenario are illustrated in Figure 13. This figure indicates that the coal with sequestration scenario is preferable on a CO_2 emissions basis with about a third of the emissions as the onsite production scenario. Both of the hydrogen scenarios considered in this study are preferable to a gasoline-based infrastructure using advanced ICE's. If hydrogen is produced from coal without sequestration well to wheels CO2 emissions are higher than for the advanced gasoline case. Much of the emissions for hydrogen from coal with CCS arise from compression electricity, which is assumed to come from Ohio's current electricity mix. If future electricity came instead from IGCC coal plants with CCS, the well to wheels carbon emissions would be about 50% less than the value shown in Figure 13.)

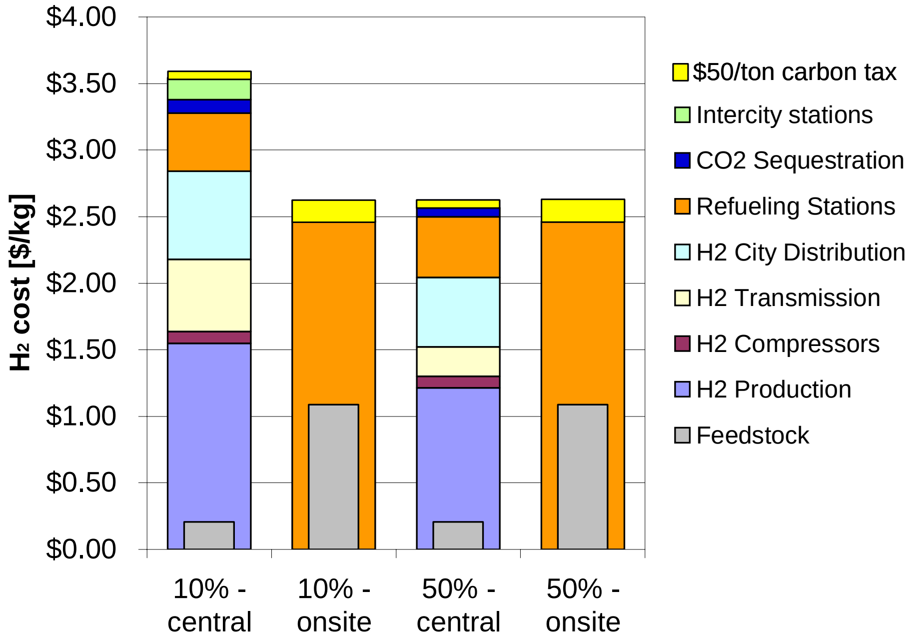

Figure 11: Comparison of levelized H_2 cost for the four scenarios

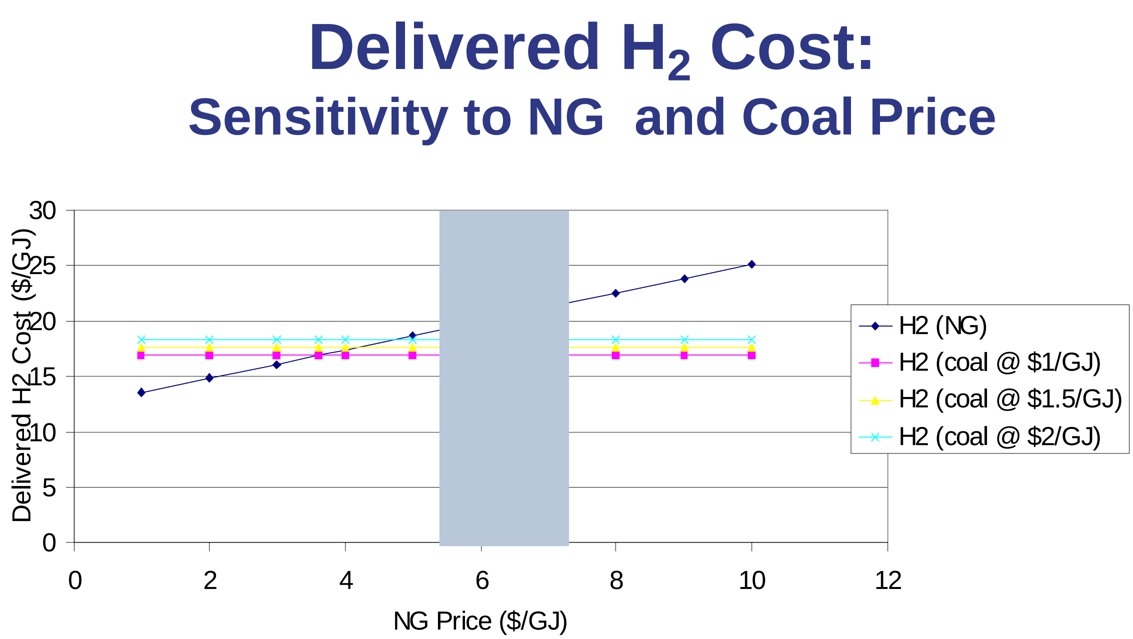

Figure 12. Sensitivity of Delivered Hydrogen Cost to Natural Gas Price and Coal Price for a 600 tonne per day Hydrogen Plant. The shaded area Indicates Natural Gas Prices of $5.5-7/MMBTU

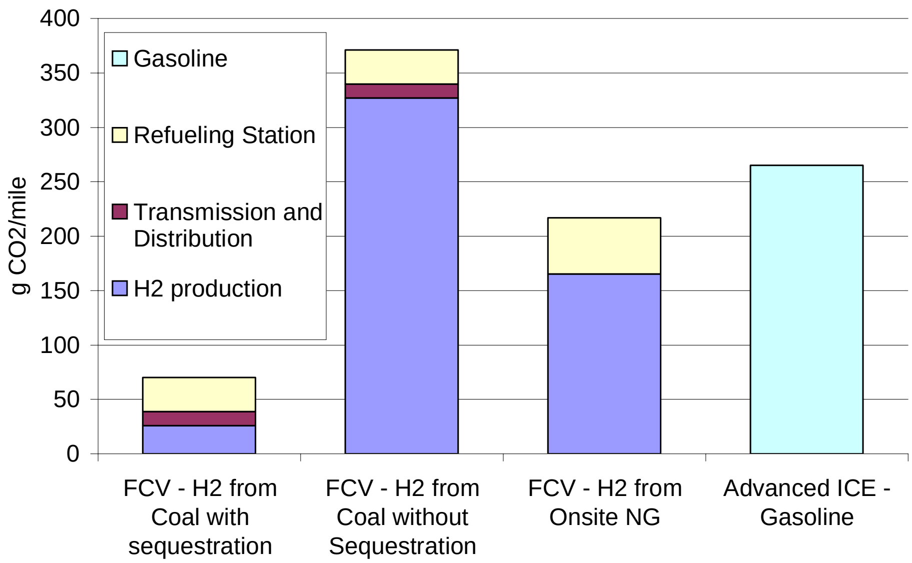

Figure 13: Comparison of well-to-wheels CO_2 emissions

5. Conclusion

We have developed methods that combine spatial tools and geographic data with engineering and economic models to understand the design and economics of regional fossil hydrogen infrastructure with carbon capture and sequestration. Initially, we focused on a case study in Ohio. However, these methods can be applied to other regions of the US. We designed optimized hydrogen infrastructure and estimated costs, performance and emissions for various steady-state demand scenarios

In the future, we will extend this work to different regions of the US to conduct a national case study, in coordination with the Department of Energy's National Energy Technology Laboratory, NATCARB and the Regional Sequestration Partnerships.

Acknowledgments

The authors are grateful for support from the National Energy Technology Laboratory, the US Department of Energy and the Hydrogen Pathways Program at the University of California, Davis.

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