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A GIS-based assessment of coal-based hydrogen infrastructure deployment in the state of Ohio

Nils Johnson[a,*], *Christopher Yang*[a], *Joan Ogden*[a,b]

[a]*Institute of Transportation Studies, University of California, Davis, CA 95616, USA*
[b]*Department of Environmental Science and Policy, University of California, Davis, CA 95616, USA*

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ABSTRACT

Hydrogen infrastructure costs will vary by region as geographic characteristics and feedstocks differ. This paper proposes a method for optimizing regional hydrogen infrastructure deployment by combining detailed spatial data in a geographic information system (GIS) with a technoeconomic model of hydrogen infrastructure components. The method is applied to a case study in Ohio in which coal-based hydrogen infrastructure with carbon capture and storage (CCS) is modeled for two distribution modes at several steady-state hydrogen vehicle market penetration levels. The paper identifies the optimal infrastructure design at each market penetration as well as the costs, CO_2 emissions, and energy use associated with each infrastructure pathway. The results indicate that aggregating infrastructure at the regional-scale yields lower levelized costs of hydrogen than at the city-level at a given market penetration level, and centralized production with pipeline distribution is the favored pathway even at low market penetration. Based upon the hydrogen infrastructure designs evaluated in this paper, coal-based hydrogen production with CCS can significantly reduce transportation-related CO_2 emissions at a relatively low infrastructure cost and levelized fuel cost.

1. Introduction

The use of hydrogen as a light-duty transportation fuel requires the development of a widespread regional hydrogen infrastructure, including production facilities, a distribution network, and refueling stations. In the case of coal-based hydrogen production with carbon capture and sequestration, additional infrastructure is needed for carbon dioxide (CO_2) disposal. To facilitate the development of this new infrastructure, it is desirable to identify deployment strategies that minimize cost and CO_2 emissions while meeting regional demand. This paper proposes an infrastructure model that employs a geographic information system (GIS) to optimize infrastructure design for a given region.

Several studies have evaluated the costs of hydrogen infrastructure components [1–3] and generic production and delivery pathways [4–9]. However, there is limited research that analyzes infrastructure cost and design for real geographic regions. Spatially explicit modeling of hydrogen infrastructure deployment has generally been conducted in two areas: (1) detailed modeling for individual cities and (2) regional modeling that employs simplified spatial representations.

In the first area, several steady-state models examine methods for optimizing hydrogen refueling station siting [10–12] and hydrogen delivery [2] for individual cities. A few studies have completed case studies of complete infrastructure pathways in Southern California in which the region is

* *Corresponding author*. Tel.: +1 530 752 1599; fax: +1 530 752 6572.
E-mail address: njohnson@ucdavis.edu (N. Johnson).
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treated as one large demand node (i.e., like a single city) [13,14]. Moreover, two studies model infrastructure deployment in urban Beijing [15,16]. The papers by Lin et al. employ dynamic programming to examine the deployment of infrastructure over a planning horizon [14,15]. Although these studies yield insights into infrastructure deployment for individual cities, their applicability is limited when considering an entire region, which requires an infrastructure optimized to serve multiple cities. In addition, the studies of complete infrastructure pathways employ simplified spatial representations to facilitate modeling.

In the second area, studies have been completed that employ complex optimization algorithms and scenario-based analyses to model infrastructure deployment in large regions [17–22]. However, these analyses generally use simplified spatial representations of hydrogen demand and distribution networks. In particular, significant work has been conducted as part of the European HySociety project [23–25]. Two studies have also been conducted that use GIS to model hydrogen refueling station deployment for the entire U.S. at a coarse scale [26,27]. Although these models provide valuable insights into regional infrastructure development, they do not account for the spatial complexity inherent in individual regions.

This paper proposes a GIS-based method for modeling regional hydrogen infrastructure deployment using detailed spatial data and applies the method to a case study of a potential coal-based hydrogen transportation system in Ohio with CO_2 capture and storage (CCS). The objective is to optimize hydrogen infrastructure design for the entire state at several steady-state[1] hydrogen vehicle market penetration levels. GIS facilitates this analysis by allowing use of spatially referenced data (e.g., population distribution and existing infrastructure) to calculate the location and magnitude of hydrogen demand and optimize the placement and extent of hydrogen production facilities and transportation routes for moving hydrogen and carbon dioxide. Technoeconomic models that describe the costs and technical performance of infrastructure components are applied to calculate the costs, energy usage and CO_2 emissions of different hydrogen infrastructure options. Comparing these options, the lowest cost infrastructure design for supplying hydrogen to users is identified at each market penetration. The goal of this research is to increase understanding of the economics and design issues related to hydrogen infrastructure development under real-world geographic constraints.

2. Infrastructure cases

As methods for spatial modeling of regional hydrogen infrastructure deployment are the focus of this paper, we examined a limited set of potential hydrogen infrastructure pathways in order to provide context for their application. Specifically, one hydrogen production technology, two distribution modes, and five market penetration levels are modeled and compared. The production technology is centralized production of hydrogen using coal gasification with capture and sequestration of CO_2 and the hydrogen distribution modes include both cryogenic liquid hydrogen trucks and compressed gas pipelines, which are the major transport and distribution modes for moving significant quantities of H_2 [2]. For each supply pathway, infrastructure is designed and evaluated at five steady-state hydrogen fuel cell vehicle (HFCV) market penetration levels (5%, 10%, 25%, 50%, and 75%). This analysis allows us to examine how the lowest cost pathway might differ for early and more mature hydrogen markets. The centralized infrastructure results are also compared with a fixed cost for hydrogen production via onsite steam methane reformation in order to identify which production mode has the lowest cost at each market penetration [28].[2]

In evaluating each case, several simplifying assumptions are made: (1) infrastructure is optimized independently at each market penetration level (i.e., without regard to past or future infrastructure installments), (2) infrastructure is optimized to meet a particular market demand and is fully utilized upon completion, (3) the study area is a closed system in which hydrogen is neither imported nor exported, and (4) infrastructure within the study area is constructed and operated by a single entity so that economies of scale are most effectively captured.

3. Methods and model description

To model hydrogen infrastructure deployment in a specific region, both spatial data and technoeconomic models of infrastructure components are required. The first section describes the GIS-based methods for infrastructure design and the second section describes the technoeconomic models used for quantifying the costs, energy use, and CO_2 emissions of each infrastructure case.

3.1. *Infrastructure design*

This section focuses on the GIS-based modeling tools that have been developed for optimizing hydrogen infrastructure for a given region at a specified market penetration level. In particular, the methodologies for modeling hydrogen demand and optimizing infrastructure are summarized.

3.1.1. *Spatial data*

In performing the GIS analysis, several existing spatial datasets were used, including census block population [29], existing coal power plants [30], existing pipeline rights-of-way [31], brine well locations [32], and interstate highways [33]. These datasets are illustrated in Fig. 1. The US Census data is used to estimate potential hydrogen demand density based on the existing distribution of population density. The existing coal power plants and pipeline rights-of-way are

[1] A steady-state model assumes that conditions are not changing. Thus, infrastructure is modeled at each market penetration level without considering the transitions between these states (i.e., the model does not consider the infrastructure required at previous and future states).

[2] It is assumed that each onsite production station has a design capacity of 1500 kg/day and the levelized cost of delivered hydrogen is $3.49/kg at all market penetration levels.

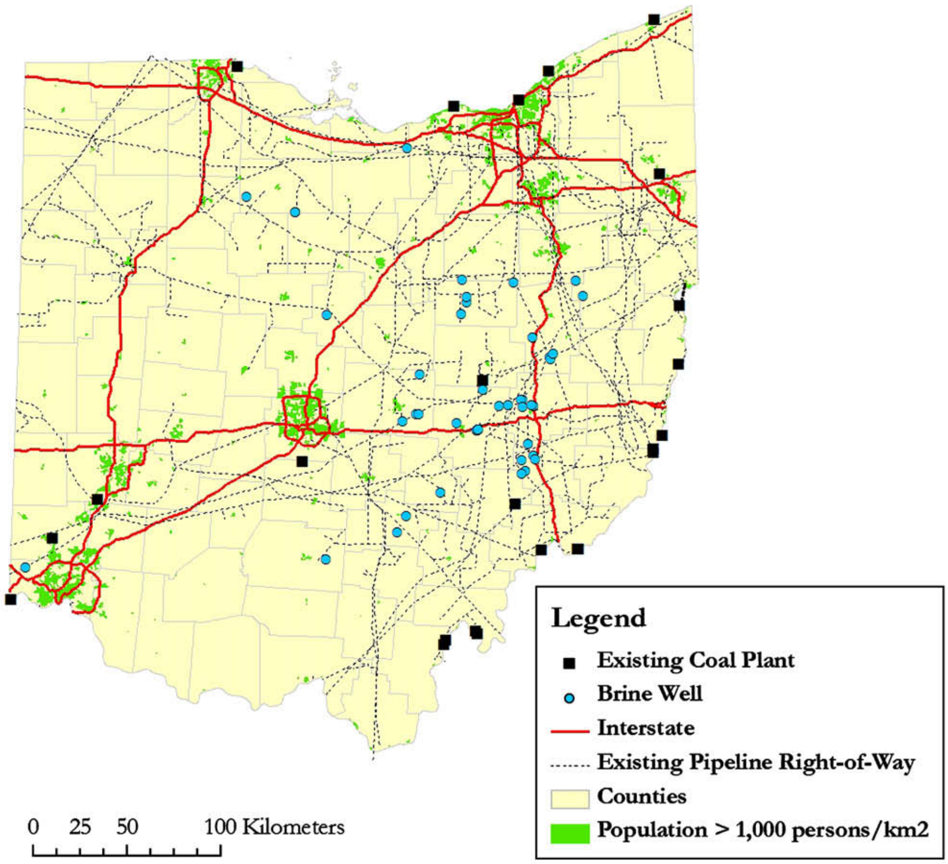

Fig. 1 – Ohio GIS datasets.

used to constrain hydrogen infrastructure analysis by assuming that existing coal plants will serve as potential sites for new coal-to-hydrogen facilities and hydrogen pipelines will follow existing rights-of-way. Brine wells access deep saline aquifers, which are potential reservoirs for CO_2 sequestration. Consequently, these wells act as proxies for CO_2 sequestration sites.[3] The use of existing datasets helps to constrain the number of possible distinct infrastructure designs, which improves the tractability of the spatial optimization problem.

3.1.2. *Modeling hydrogen demand*

The design of a hydrogen fuel delivery infrastructure depends on the spatial characteristics of the hydrogen demand. In this study, the magnitude and spatial distribution of hydrogen demand is modeled based on exogenously derived market penetration levels and census population data [34]. This study examines steady-state (i.e., non-transition) market penetration scenarios in which demand is derived based on fixed percentages of statewide HFCV penetration (e.g., 10% of existing light-duty vehicles (LDV)).

Census-derived population density, which is mapped at the census block level, is used to calculate hydrogen demand density[4] for each block. Buffers of five kilometers width are then applied in the GIS to areas of high demand density (defined as >150 kg/km^2/day in this study) to aggregate neighboring census blocks into demand clusters [34]. The aggregate hydrogen demand within each cluster is then calculated and a threshold (i.e., filter) is applied to retain only the clusters with sufficient hydrogen demand to warrant investment in infrastructure (defined as >3000 kg H_2/day in this study). These remaining clusters are considered the viable hydrogen "demand centers" to which hydrogen should be supplied at a given HFCV penetration. This method provides a simple means for identifying potentially viable locations for hydrogen infrastructure investment at static market

[3] More detailed data of CO_2 sequestration sites and capacity are currently being developed by the National Carbon Sequestration Partnership (NATCARB) and will be incorporated into future analysis.

[4] The equation for calculating hydrogen demand density is given as: HyDemand = PopDens × VehOwn × HyUse × MarketPen where HyDemand is the hydrogen demand density (kg H_2/km^2/day) in each census block, PopDens is the population density (people/km^2) given by the US Census, HyUse is the projected average daily hydrogen use per vehicle (0.6 kg H_2/HFCV/day), VehOwn is the per-capita light-duty vehicle ownership (0.7 LDV/person), and MarketPen is the HFCV market penetration (No. of HFCV/no. of LDV). HyUse is calculated by assuming that the average annual mileage driven by an LDV is 12,000 miles and a HFCV achieves a fuel economy about 2.5 times that of a current gasoline LDV (~57 miles per kg of hydrogen).

penetration levels. Though not included in this study, additional criteria could be used to further refine the spatial distribution of hydrogen demand by examining the location of likely markets for hydrogen vehicles, including household income, number of registered vehicles, or local policies [35].

It is important to note that the market penetration refers to the statewide market penetration. In other words, at 5% market penetration, it is assumed that 5% of the vehicles in the entire state are HFCVs. However, since hydrogen is only being supplied to the designated demand centers, it is assumed that all of these vehicles operate within these areas. Consequently, in order to achieve the desired statewide market penetration level, the market penetration (i.e. fraction of vehicles operating on H_2) within the demand centers is higher. Table 1 indicates the actual market penetration within the demand centers for each of the five statewide market penetration levels considered in this study.

The characteristics of the identified demand centers at each market penetration level are listed in Table 2. By concentrating hydrogen infrastructure in population centers, service can be provided to a large proportion of the statewide population in a relatively small fraction of the land area. For example, at 5% market penetration, 42% of the population resides in the demand centers, which occupy only 4% of the land area of Ohio.

3.1.3. *Optimizing supply: production and intercity transmission*

Given the location and quantity of hydrogen demand, the next step is to optimize the siting of hydrogen production facilities and distribution networks for delivering hydrogen to the demand centers. The potential locations for new coal-to-hydrogen facilities are constrained to the locations of existing coal plants and their maximum hydrogen production capacities are limited by the quantity of coal input available to the existing power plants. Data regarding Ohio coal plants are available from the United States Environmental Protection Agency (US EPA) eGrid database, which provides information such as electricity output, annual heat input, plant efficiency, and CO_2 and other important emissions [30].

3.1.3.1. Hydrogen production potential. The hydrogen production potential of each existing coal power plant larger than 100 MW_e is calculated based on the existing annual coal input and the assumption that each plant is converted to a coal gasification facility with a coal-to-hydrogen efficiency of 57.5% [36]. The hydrogen production potential of each coal plant in Ohio is listed in Table 3 with the largest coal facility capable of producing more than 2400 tonnes of H_2 per day. Consequently, it is possible that a single coal-to-hydrogen facility could meet statewide hydrogen demand for a scenario approaching nearly 50% market penetration. If all of the coal facilities statewide were converted to produce only hydrogen, they could produce enough hydrogen to supply approximately 30 million hydrogen vehicles (~18,200 tonnes/day), which is greater than three times the number of gasoline vehicles currently in Ohio. Given the production potential of each plant, the next step is to identify the coal facility or facilities that minimize the cost of hydrogen and CO_2 distribution, which is determined by the total length of the pipeline or truck networks for hydrogen delivery and the length of required CO_2 pipeline.

Table 1 – Statewide market penetration scenarios

State-wide market penetration (%)	Market penetration within demand centers (%)
5	12
10	18
25	38
50	68
75	99

3.1.3.2. Pipeline distribution. In the pipeline case, existing pipeline rights-of-way from the US Department of Energy GasTrans database are used to constrain the potential locations for hydrogen pipelines [31]. To assess the optimal pipeline network, a GIS is used to identify the shortest distance pathways between all the coal facilities and the centroids of the demand centers as well as between the demand centers themselves. Fig. 2a shows the results of this analysis at 5% market penetration, where the lines indicate the shortest distance pathways, the large polygons represent demand centers, and the black squares represent the potential production facilities. This network represents the portfolio of possible pipeline segments that would connect coal facilities and demand centers at 5% market penetration. For each segment, the distance is calculated and then imported into a cost matrix in a spreadsheet.

A minimal spanning tree optimization algorithm is then applied to identify the minimum length pipeline network for connecting each production facility to all demand centers. The process is repeated for each production facility and the production and transmission design that results in the minimum hydrogen and CO_2 pipeline distances is selected as the optimal infrastructure at a given market penetration level. The optimized design is then imported back into a GIS for visualization. At each market penetration, the supply network is optimized for a single coal facility. In scenarios where a single plant cannot meet the demand (>25% market penetration), additional plants are added that meet the remaining demand and minimize the additional hydrogen and CO_2 pipeline distances. Fig. 2b shows the optimal supply network for the pipeline case at 5% market penetration.

3.1.3.3. Truck distribution. In the case where liquid hydrogen is transported by truck, it is assumed that the trucks travel along major state and federal highways. Starting with the existing road network [33], GIS is used to calculate the shortest distance pathways between each coal facility and each demand center. The number of trucks that would have to travel each pathway is then calculated based on the demand at each associated demand center and the capacity of the trucks. H2A indicates that the effective truck capacity is ~3900 kg after accounting for usable tank capacity and unloading and boil-off losses [8]. To calculate the total intercity truck distance for each coal facility, the number of trucks for each demand center is multiplied by the round trip

Table 2 – Demand center characteristics

Market penetration (%)	Number of demand centers	Population captured (% of state population)	Land area (% of state)	Cumulative H_2 demand (tonnes/day)
5	15	42	3.8	266
10	22	53	6.0	509
25	46	66	9.9	1337
50	78	73	13.7	2644
75	96	76	15.8	3985

distance and then these distances are summed for all the routes between the coal facility and the demand centers. It is assumed that the truck returns empty to the hydrogen production facility. The coal facility or facilities that have sufficient hydrogen production potential and minimize the total intercity truck transport distance are selected as the optimal site(s).

3.1.4. *Intracity distribution and station siting*

The preceding analysis has identified the location and quantity of demand, the location and production capacity of the coal facility, and the location of the hydrogen pipelines or truck routes. The next step is to identify the infrastructure required for delivering hydrogen to consumers within the demand center boundaries. The pipeline and truck distribution distances determined in the previous sections only include delivery to the centroid of the demand cluster. However, a network of refueling stations within the demand cluster would be distributed widely throughout the urban area along major highways and arterials [11] and would require an additional distribution infrastructure.

In this analysis, a GIS-based methodology is not used for optimizing intracity hydrogen distribution and refueling station siting. Instead, an idealized city model is used to simplify the estimation of the distribution pipeline length and number of refueling stations [2]. This model assumes that each demand center is represented by a circle of equivalent area (Fig. 3a). Within this circle, it is assumed that the population distribution is homogeneous and the refueling stations are distributed evenly and connected by pipelines or truck routes (Fig. 3b). As a result of this simplification, the distribution pipeline length and truck distances can be estimated by the demand center area and the number of refueling stations. In the truck case, it is assumed that each truck travels to a single station from the hydrogen facility and returns empty (i.e., there are no distribution depots within each demand center).

The number of hydrogen refueling stations within each demand center is set at a minimum level in order to ensure consumer convenience. Nicholas et al. [11] has shown that hydrogen provided at 10% of existing gasoline stations could provide adequate coverage for customers. Assuming that existing gasoline stations serve approximately 3000 vehicles per day [27], the total number of gasoline stations in a demand cluster is estimated by multiplying the population by the per-capita vehicle ownership rate (0.7) and then dividing this number by 3000. The minimum number of hydrogen refueling stations is assumed to equal 10% of the total estimated gasoline stations [11]. Additional stations are only added when the average demand served by each station exceeds 1800 kg/day (i.e., the average station serves ~3000 hydrogen vehicles per day). Given the number of stations and area associated with each demand center, the intracity pipeline and truck travel distances are estimated. Yang [2] and Ogden [3] give equations for calculating pipeline length and truck travel distance for each demand center as a function of the city radius and number of stations.

3.1.5. *Intercity station siting*

The final component of regional infrastructure design is the siting of intercity stations. These stations are intended to provide connectivity between demand centers so that

Table 3 – H_2 Production potential of existing coal facilities (converted to coal gasification plants)

Plant name	H_2 production potential (tonnes/day)	Plant name	H_2 production potential (tonnes/day)
Ashtabula	134	Mitchell	1176
Avon Lake	416	Mountaineer (1301)	974
Bay Shore	432	Muskingum River	1112
Cardinal	1406	Niles	183
Conesville	1510	OH Hutchings	146
Eastlake	768	Phil Sporn	882
General JM Gavin	2430	Picway	65
Hamilton	50	Pleasants	1022
Kammer	552	RE Burger	284
Kyger Creek	1056	Richard Gorsuch	240
Lake Shore	69	WH Sammis	1805
Miami Fort	1255	Willow Island	242
Total			18,210

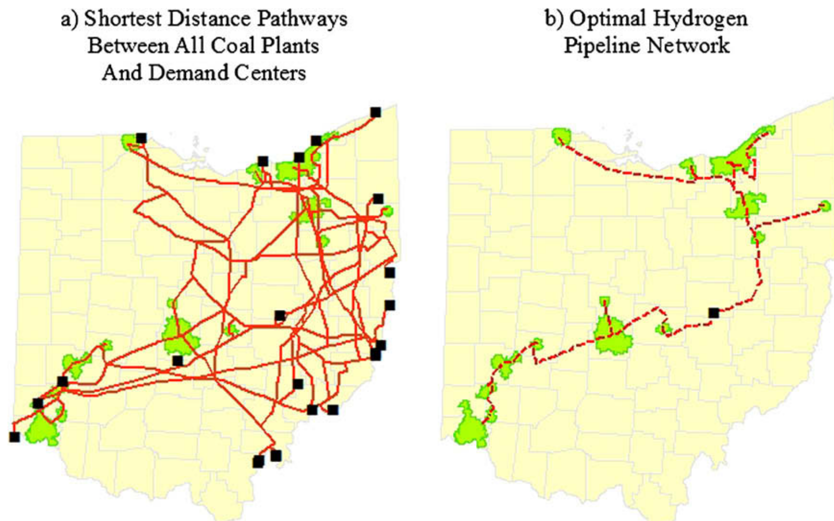

Fig. 2 – Pipeline network optimization at 5% market penetration.

hydrogen vehicle owners can travel reliably along interstate highways between demand centers. In order to optimize intercity station siting, the first step is to identify potential station sites. These sites are identified by selecting all major intersections[5] that involve interstate highways and are within five kilometers of an intercity demand cluster. The intercity demand clusters are the clusters that had adequate hydrogen demand density in the demand analysis, but did not have sufficient aggregate hydrogen demand to qualify as a demand center.

For each of the potential station sites, the following information is calculated. First, the average daily traffic (ADT) flow is estimated for each potential site based on Ohio DOT data for the highway segments that comprise each site [33]. Next, the distance from the site to the nearest demand cluster is calculated and the associated hydrogen demand of this cluster is assigned to the site. Finally, the distance from each site to the corridor endpoints (i.e., nearest demand centers) is calculated. Given this information, the optimal intercity station sites are identified by selecting potential sites that are close to large demand clusters, have significant average daily traffic flow, and are located >30 km from the corridor endpoints, or demand centers. These criteria ensure that the optimized stations will be located at sites with ample vehicle traffic, near cities with some potential local hydrogen demand, and sufficiently distant from demand centers where there are already adequate refueling stations.

Intercity stations are most important in low market penetration scenarios when the distances between demand centers can be large. At 5% market penetration, ten intercity stations are identified in which it is assumed that the hydrogen will be produced onsite using steam methane reformation. Given these stations, the maximum distance that a hydrogen vehicle owner will need to travel between hydrogen stations on the interstate highways is 145 km (90 miles) with an average distance of ~80 km (50 miles). As market penetration increases, centrally produced hydrogen is supplied to more cities and fewer intercity stations are required. For example, at 50% market penetration, one intercity station is adequate. Consistent with H2A data for onsite production, it is assumed that each intercity station has a design capacity of 1500 kg/day [28].

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

3.2. *Technoeconomic models*

Once the optimal infrastructure design (i.e. plant location, distribution layout, and sequestration site) has been determined, technoeconomic models for each of the infrastructure components are used to evaluate the cost, energy use and CO_2 emissions of the system. The models encompass the range of processes and equipment necessary for hydrogen production, distribution, refueling stations, and sequestration of carbon dioxide. A real discount rate of 10% is used for all components and values are normalized to 2005 dollars. This section summarizes the key references and assumptions used in the analysis.

3.2.1. *Hydrogen production and storage*

Hydrogen production is modeled for a large coal gasification plant with electricity co-production and carbon capture based upon designs and modeling from Kreutz et al. [1] and Chiesa et al. [36]. The capacity of each potential H_2 production plant is constrained by the location and coal input of the existing coal steam power plant as detailed in the EPA eGRID database [30]. The production plants are designed to maximize the hydrogen output (~96% of energy output) with minor electricity co-production (~4%) remaining after meeting plant electrical requirements (such as CO_2 compression). In sizing the plants, we account for hydrogen losses throughout the infrastructure. Since losses are greater in the truck case (~8.25%) than the pipeline case (~0.5%), production facilities must be slightly larger in the case of truck delivery [8].

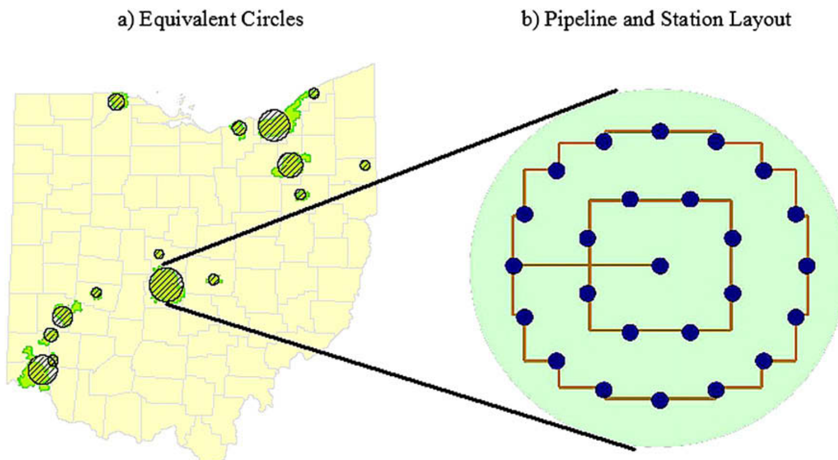

Fig. 3 – Idealized city model.

The models of coal-to-hydrogen plant costs given by Kreutz et al. [1] and Ogden et al. [37] are used to derive an equation for the scaling of the capital cost of coal-to-hydrogen plants as a function of hydrogen production capacity.

$$CC(2005\$) = \$942,749,170\left(\frac{S_p}{770,400}\right)^{0.789}$$

where S_p is the production capacity of the hydrogen facility in kilograms per day. The central plant cost includes the cost of capturing carbon dioxide for sequestration via physical absorption in Selexol, but does not include the cost of CO_2 compression. The total annual cost for constructing and operating the plant includes the annualized capital cost, O&M costs, feedstock costs, and revenue from electricity co-production. The assumptions used in deriving plant economics, energy use, and CO_2 emissions are listed in Table 4.

At the central plant, hydrogen is stored in order to ensure a reliable supply. Equations describing the cost and performance of current gaseous and liquid hydrogen storage technologies are given by H2A [8]. For the pipeline case, it is assumed that a suitable cavern for geologic storage is available near the production facility. Sufficient usable cavern capacity is required to store about 12 days of demand given the assumption that each plant will experience about 120 days each year in which demand will surge by a maximum of 10% above the average daily demand [8]. The hydrogen losses, energy use, and CO_2 emissions associated with gaseous storage are considered negligible since a relatively small amount of hydrogen is stored. For cases in which the H_2 is liquefied, LH_2 storage vessels with a maximum capacity of 450 tonnes are assumed [8]. The number of required vessels is calculated based on the assumption that five days of LH_2 storage is required [8]. It is assumed that hydrogen is available from the pressure swing adsorption (PSA) unit of the production plant at 60 bar [36] and, thus, compression is not required for hydrogen that is immediately transferred to a pipeline without intermediate storage.

Table 4 – Hydrogen production assumptions

Parameter	Value	Source
Plant capacity factor	80%	[1]
Plant lifetime (years)	40	[5]
Plant CRF	10.2%	–
η_{H2} (LHV)	57.46%	[1]
η_{Elec} (LHV)	2.09%	[1]
Heat rate (MMBTU coal/kg H_2)	0.198	
Plant O&M	4% of overnight capital	[1]
Electricity sales price (2005$)	$0.05/kWh	-
Coal type	Illinois no. 6	[36]
Coal price (2005$)	$1.29/MMBTU	[38]
CO_2 emissions (no capture)	93.8 kg CO_2/MMBTU coal	[39]
CO_2 captured at plant	91%	[1]

3.2.2. CO_2 sequestration

In the plant design chosen, ~91% of the CO_2 is captured and sequestered while 9% is emitted into the atmosphere [36]. 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 sequestration site where it will be injected into an underground geologic formation such as a deep saline aquifer. In the case of multiple hydrogen production facilities, CO_2 capture and transport equipment is associated with each plant. However, it is possible for multiple plants to supply a single injection site.

After the CO_2 is captured via physical absorption, it is compressed to supercritical pressure at 15 MPa, which permits efficient pipeline transmission of the CO_2. It is assumed that a compressor is used to compress the CO_2 from atmospheric pressure to the critical pressure of 7.38 MPa, at which point, a pump is used to increase the pressure to 15 MPa [40]. Assuming that compression will be conducted in five stages, the required compressor power is estimated. According to the IEA GHG PH4/6 report [41], the maximum size of one compressor train, based on current technology, is 40,000 kW. Consequently, if the total compression power requirement is more than 40,000 kW, the CO_2 flow rate and total power requirement is split into multiple parallel compressor trains. The equation for estimating the capital cost of the compressor(s) as a function of number and size is given by Kreutz et al. [1].

Once the CO_2 is compressed to 15 MPa, it is ready for transport by pipeline. The equation for onshore pipeline capital cost as a function of CO_2 flow rate and pipeline length is given by McCollum [40]. Aside from CO_2 compression, it is assumed that the energy use and CO_2 emissions associated with pipeline transport are negligible.

At the sequestration site, the CO_2 is injected into an underground geological reservoir, such as a deep saline aquifer. Although the injection rate of CO_2 depends on the characteristics of the reservoir, we assume a maximum injection rate of 2500 tonnes of CO_2 per day [37]. Using an injection well capacity factor of 80%, we are able to estimate the number of wells (N_{well}) required for each scenario. Capital and O&M costs are estimated using information provided by Smith [42] and Herzog et al [43]. The total CO_2 sequestration cost is calculated by summing the annual costs of CO_2 compression, pipeline distribution, and injection. Energy use and CO_2 emissions from CO_2 sequestration are assumed to be predominately associated with compression.

3.2.3. *Hydrogen transmission and distribution pipelines*

In the pipeline scenarios, pipelines are used for the ''transmission'' of hydrogen from the central hydrogen production plant to each of the demand centers as well as ''distribution'' within each of the demand centers to the network of refueling stations located within those clusters. For distribution pipelines within demand centers, the steady-state performance of the ringed network of pipelines is not explicitly modeled. Rather, it is assumed that all pipelines within a particular demand center are sized to meet the total mass flow rate of H_2 to the demand center. Consequently, a single pipeline diameter and length is used to cost distribution pipelines within each demand center. Although this may overestimate the diameter and, thus, cost of intracity pipelines, the estimates appear to be acceptable since the costs associated with small pipelines are mainly due to installation and right-of-way (ROW) as opposed to the diameter and material cost of the pipeline itself. Assuming that the demand centers are predominately urban, the installation and ROW cost is assumed to be $600,000 per kilometer. The cost of materials for distribution pipelines is given by Parker [44]. For transmission pipelines, the mass flow rate of H_2 in each segment is calculated and used to estimate the associated pipeline diameter. The costs of transmission pipelines as a function of diameter and length are derived from equations for natural gas pipelines [44].

3.2.4. *Hydrogen liquefaction and truck transport*

Large-scale hydrogen transport via liquid trucks is the other hydrogen delivery option that is considered. Liquefaction can greatly increase the volumetric density of hydrogen, as compared to compressed gas, which helps reduce the transport costs, but the liquefaction process itself is very capital and energy intensive. In each of the market penetration scenarios, liquefaction plants are assumed to be co-located with each central hydrogen production plant and are sized for the hydrogen production flow rate from the associated plant. The performance and cost of liquefaction and truck transport components are given by H2A for current technology [8]. In sizing each liquefier, a capacity factor of 70% and maximum liquefier size of 300 tonnes/day are assumed. If the liquefaction plant must liquefy greater than 300 tonnes/day, multiple liquefiers of equal size are installed. Liquefier electricity use (kWh/kg H_2) is estimated as a function of size [8] with a minimum electricity use of 9.25 kWh/kg H_2 for the most efficient, large liquefiers.

Associated with each production facility is a hydrogen terminal that is used to load liquid hydrogen onto trucks. The terminal includes pumps and loading facilities. H2A gives current costs for terminal components [8]. The energy use, associated CO_2 emissions, and hydrogen losses of the terminal and pumps is considered negligible [8].

The final component of the LH_2 truck transport pathway is the trucks themselves. In order to calculate the cost and performance of the trucks, we use the assumptions given by H2A [8]. Given the number of truck trips and total truck driving distance, the daily time required to deliver the H_2 is calculated based on travel times and load and unload times. This calculation determines the number of driver hours and total trucks required for delivery. Given the number of trucks, the capital costs of cabs and trailers are calculated [8]. The annualized capital cost assumes a lifetime of 5 years for the cabs and 20 years for the trailers. The annual O&M costs include labor, fuel, overhead, fixed O&M, and miscellaneous fixed costs.

3.2.5. *Refueling stations*

In modeling the hydrogen refueling stations, an average station size is used to represent the size of all stations and a 70% capacity factor is assumed [8]. For stations to which gaseous hydrogen is delivered via pipeline, the stations include compressors, hydrogen storage and dispensing. In the case of stations supplied by liquid hydrogen trucks, the station components are similar, but pumps are used rather than compressors to supply pressurized gaseous hydrogen to the dispensers. Regardless of delivery mode, gaseous hydrogen is supplied to vehicles at 6000 psi. The average station size is calculated by dividing the total hydrogen demand by the number of stations. Equations developed by H2A [8] are used to estimate the current capital and O&M costs of individual pipeline and liquid truck stations. For each station type, the energy cost and CO_2 emissions associated with operating the station are also calculated. An electricity cost of $0.075/kWh is assumed at stations. All intercity stations include onsite production via steam methane reformation and are assumed to have a design capacity of 1500 kg/day. Each station is assumed to have a capital cost of $3.2 million, an overall energy efficiency of 64%, and emit 13.3 kg CO_2 equivalent per kg H_2 delivered [28,45]. The natural gas feedstock cost is $6.62 per MMBTU.

4. Metrics and results

Given the optimized infrastructure design for each scenario, four metrics are evaluated and compared: (1) levelized cost of hydrogen, (2) capital cost of hydrogen and CO_2 infrastructure (3) well-to-tank energy efficiency, and (4) well-to-wheels CO_2 emissions. Delivered hydrogen cost will play a major role in determining when (and whether) hydrogen is competitive with other fuels and which pathway is preferable.[6] Estimation of infrastructure capital costs is important for indicating the total investment needed to build the system. Overall energy efficiency and CO_2 emissions are important metrics to consider since they indicate the energy use and climate change impacts associated with each hydrogen pathway. In an attempt to quantify the benefits of reducing CO_2 emissions, we examine the impacts of two carbon reduction scenarios: a $50/tonne carbon tax and decarbonized grid electricity (DCE). It is assumed that CO_2 emissions (g/mile) and energy efficiency vary minimally with market penetration. Consequently, these metrics are summarized at a single market penetration level (25%) in the first section. In the remaining sections, infrastructure design and cost is reported for each market penetration level and the sensitivities of various model parameters are examined.

4.1. *Energy efficiency and CO_2 emissions*

Well-to-tank energy efficiency is reported as the percentage of the total energy input that is captured as hydrogen on a lower heating value (LHV) basis. A key input for calculating this metric is the Ohio electrical grid mix efficiency of 36% [30]. Of the two centralized cases, distribution via pipeline is significantly more efficient than distribution via LH_2 trucks. In the pipeline case, the overall energy efficiency is approximately 50% with most of the loss occurring during the conversion of coal to hydrogen at the production plant (57% efficiency). In contrast, the LH_2 truck case has an overall efficiency of ~36% because substantial electricity is required to liquefy hydrogen.

As market penetration increases, the additional electricity required for liquefaction becomes substantial. For example, at 75% market penetration, a 1500 MW power plant would be required to supply the electricity for liquefying hydrogen in the truck case. This represents ~9% of the total electricity demand of Ohio in 2002 [46], resulting in additional coal demand and associated emissions and/or sequestration requirements. Table 5 lists the additional power requirements resulting from hydrogen liquefaction at each market penetration.

For calculating CO_2 emissions, we use 0.811 kg CO_2/kWh for electricity-related emissions [30], 93.8 kg CO_2/MMBTU for coal-related emissions [39], 12 kg CO_2/gallon for diesel-related emissions [5], and 11.2 kg CO_2/gallon for gasoline-related emissions [6]. Emissions are calculated on a gram per mile basis assuming that fuel cell vehicles operating on hydrogen achieve 57 miles per kilogram and advanced ICE vehicles operating on gasoline obtain 40 miles per gallon. Fig. 4 compares well-to-wheels CO_2 emissions for each infrastructure case, including two additional cases in which (1) coal-related emissions are vented and (2) grid electricity is decarbonized. In the decarbonized electricity (DCE) case, we assume that all power plants in Ohio are IGCC plants with CCS as modeled by Chiesa et al. [36]. It is assumed that the coal-to-electricity efficiency is 37%, carbon capture is 91%, and the electricity price increases $0.02/kWh over the baseline [47].

[6] Other important factors will include the cost, performance, and range of HFCVs, but vehicle characteristics are not the focus of this study.

Table 5 – Power demands of hydrogen liquefaction

Market penetration (%)	Power demand (MW)	% Total Ohio demand (2002)
5	103	0.58
10	196	1.11
25	515	2.93
50	1019	5.79
75	1536	8.72

Emissions for advanced gasoline internal combustion engine (ICE) vehicles are provided as a reference.

This figure illustrates the importance of capturing emissions from coal production facilities since the cases in which the CO_2 is vented result in 33% and 77% *increases* in well-to-wheels CO_2 emissions for HFCVs relative to advanced gasoline vehicles for the pipeline and truck cases, respectively. However, with carbon capture and sequestration (CCS) at the coal plant, emissions associated with hydrogen production decrease dramatically, resulting in 73% and 29% reductions in emissions relative to gasoline for the pipeline and truck cases, respectively. The reduction in emissions is more moderate for the truck case as a result of the electricity-related emissions for hydrogen liquefaction.

However, if it is assumed that grid electricity is decarbonized, emission reductions associated with the truck case resemble those for the pipeline case. With decarbonized electricity, reductions relative to gasoline are 88% and 83% for the pipeline and truck cases, respectively. Onsite H_2 production via steam methane reformation results in a relatively small 17% decrease in CO_2 emissions per mile relative to gasoline vehicles since capturing and sequestering CO_2 from individual refueling stations is currently not economically feasible. Consequently, it is concluded that centralized coal-based H_2 production with CCS promises a greater CO_2 reduction potential than onsite production.

4.2. *Hydrogen infrastructure design and cost*

The optimized infrastructure design, associated capital cost, and levelized cost of hydrogen are summarized for each infrastructure case. Levelized costs are also presented for a case in which a $50/tonne carbon tax is imposed.

4.2.1. *Infrastructure design and capital cost*

At each market penetration level, hydrogen infrastructure deployment is optimized for both pipeline and truck distribution. Fig. 5 presents the optimal infrastructure design for the pipeline case at 5%, 25%, and 75% HFCV market penetration. These examples suggest how hydrogen infrastructure might grow to meet increasing demand. In the 5% case, the pipeline network is relatively simple with service to the most populous cities in Ohio. Since hydrogen service is limited, 10 intercity stations are required in order to allow HFCV owners to travel between the demand centers. As market penetration increases, the demand centers both grow in size and increase in number as more cities become viable demand centers. At 75% market penetration, an elaborate pipeline network spans the majority of the state, intercity stations become unnecessary, and

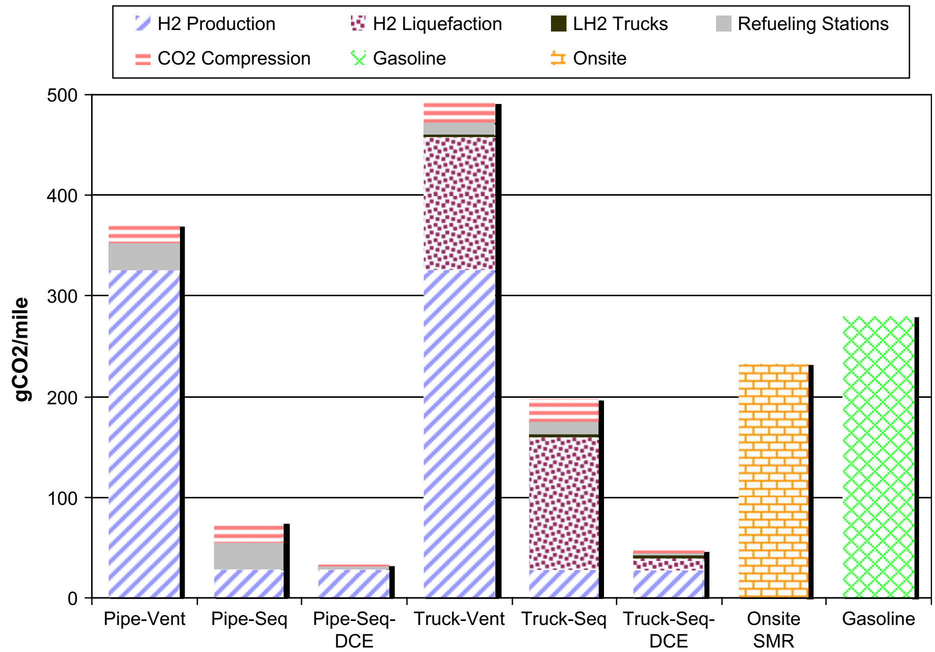

Fig. 4 – Well-to-wheels CO_2 emissions per mile for various hydrogen infrastructure cases. (Vent = CO_2 vented, Seq = CO_2 sequestered, DCE = decarbonized electricity sector.) Emissions for onsite SMR stations and advanced gasoline vehicles are shown for comparison.

hydrogen demand is sufficient to require three hydrogen production facilities. Infrastructure designs for the truck case are not illustrated since the distribution networks are very complex and not easily visualized. In addition, the production facility locations and demand centers remain identical to the pipeline case at each market penetration level.

A detailed list of the infrastructure components and total capital cost for each infrastructure case is given in Table 6. This table indicates that many components (e.g., liquefiers, CO_2 compressors, and liquid storage vessels) exceed their maximum per-unit size at early market penetration levels and, thus, require the installation of multiple units. For this reason, these components do not benefit from economies of scale beyond 10% statewide market penetration. Similarly, the average size of refueling stations approaches maximum capacity at 5% market penetration so cost reductions are limited from this component. However, the number of inter-city stations does decline as market penetration increases.

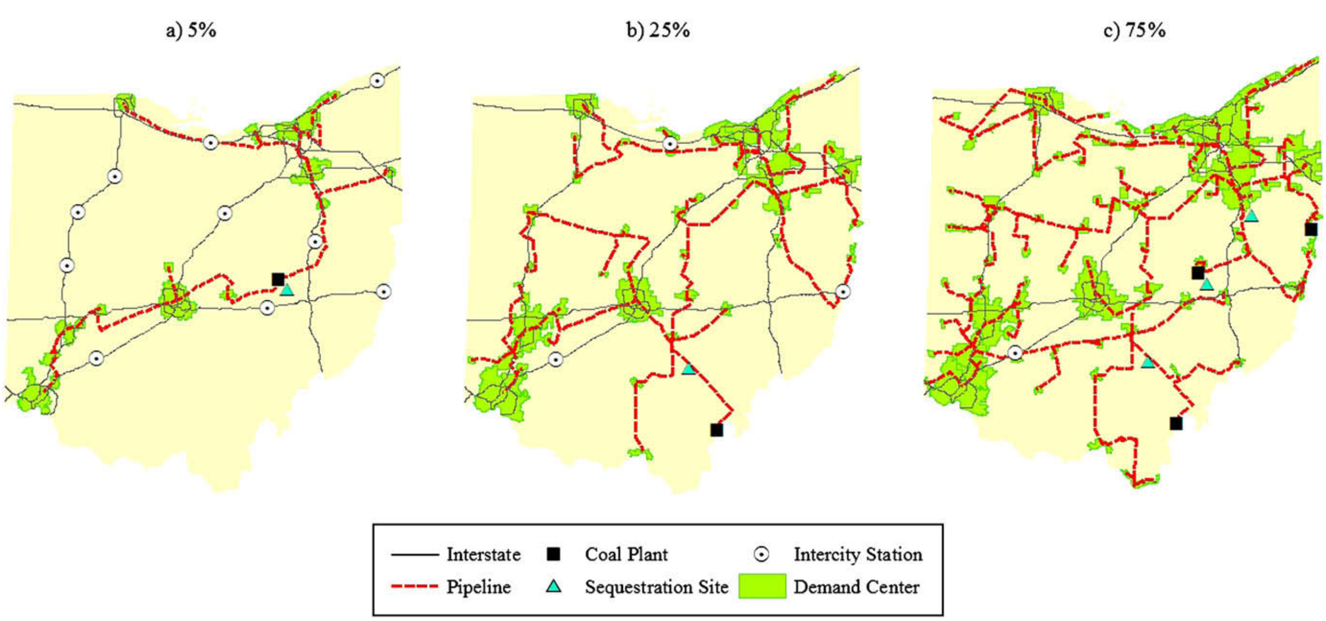

Fig. 5 – Optimal hydrogen infrastructure design for the pipeline infrastructure case at (a) 5%, (b) 25%, and (c) 75% market penetration.

Table 6 – Summary of infrastructure components and total costs

Market Penetration	5%		10%		25%>		50%		75%	
Distribution model	Pipeline	Truck	Pipeline	Truck	Pipeline	Truck	Pipeline	Truck	Pipeline	Truck
Demand										
Demand centers	15	15	22	22	46	46	78	78	96	96
Average daily demand (tonnes/day)	266	266	509	509	1337	1337	2644	2644	3985	3985
Vehicles served (thousands)	444	444	848	848	2228	2228	4407	4407	6642	6642
Production										
No. of facilities (size-tonnes/day)	1 (334)	1 (362)	1 (639)	1 (692)	1 (1680)	1 (1819)	2 (1945; 1377)	2 (2220; 1377)	3 (1983; 1377; 1647)	3 (2399; 1377; 1647)
No. of liquefiers (size-tonnes/day)	N/A	2 (207)	N/A	3 (264)	N/A	7 (297)	N/A	9 (282); 6 (262)	N/A	10 (274); 6 (262); 7 (269)
Storage										
No. of storage caverns (size-tonnes)	1 (3862)	N/A	1 (7382)	N/A	1 (19,399)	N/A	2 (22,573; 15,985)	N/A	3 (23,023; 15,989; 19,113)	N/A
No. of liquid storage vessels (size-tonnes)	N/A	4 (400)	N/A	7 (437)	N/A	18 (447)	N/A	22 (446); 14 (435)	N/A	24 (442); 14 (435); 17 (428)
CO_2 sequestration										
Capacity (tonnes/day)	4541	4918	8679	9400	22,807	24,702	45,106	48,853	67,992	73,639
Pipeline length (km)	14	14	14	14	59	59	74	74	145	145
No. of compressors (size – MW)	1 (20)	1 (22)	1 (39)	2 (21)	3 (34)	3 (37)	3 (39); 3 (28)	4 (34); 3 (28)	4 (30); 3 (28); 3 (33)	4 (36); 3 (29); 3 (33)
No. of injection wells	3	3	5	5	12	13	24	26	36	39
$/tonne C (compression, transport and storage)	16.95	16.15	13.90	14.90	16.43	16.19	15.28	15.53	16.18	16.01
Distribution										
Intracity pipeline (km)	934	N/A	1627	N/A	3423	N/A	5608	N/A	7396	N/A
Intercity pipeline (km)	931	N/A	1241	N/A	2305	N/A	3199	N/A	3626	N/A
Daily trucking distance (km)	N/A	23,659	N/A	45,704	N/A	182,787	N/A	271,399	N/A	354,687
No. of trucks	N/A	33	N/A	62	N/A	196	N/A	340	N/A	484
No. of filling bays at terminals	N/A	13	N/A	24	N/A	62	N/A	123	N/A	185
Refueling stations										
No. of city stations	154	154	293	293	766	766	1503	1503	2259	2259
Average city station design capacity (kg/day)	2469	2469	2480	2480	2493	2493	2513	2513	2520	2520
No. of intercity stations (1500 kg/day)	10	10	7	7	3	3	1	1	0	0
Costs										
Total capital cost (billion 2005$)	1.60	1.30	2.74	2.21	5.90	5.24	10.46	10.46	15.08	15.81
2005$/vehicle	3609	2926	3235	2602	2646	2352	2373	2375	2271	2381
Levelized cost (2005$/kg H_2)	3.22	3.20	2.88	2.94	2.48	2.79	2.29	2.77	2.18	2.77

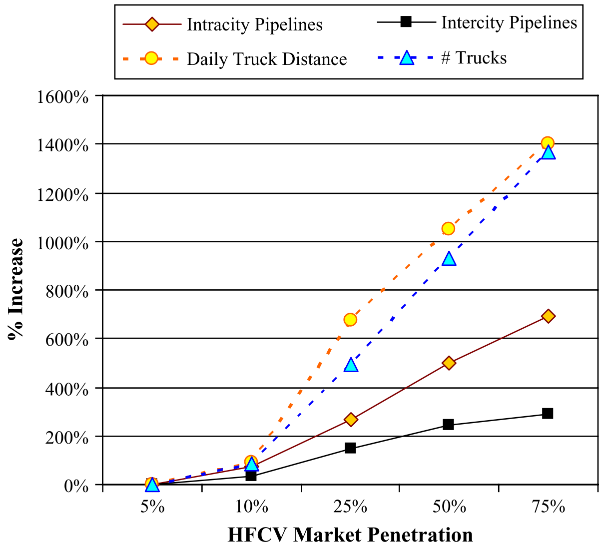

Fig. 6 – Percent increase in infrastructure requirements for distribution components from a baseline of 5% market penetration. From 5% to 75% represents a 14-fold increase in market penetration.

At hydrogen production facilities, economies of scale are captured until multiple facilities become necessary at about 50% market penetration. Similarly, infrastructure components that accompany individual facilities (e.g., CO_2 sequestration sites and cavern storage) have limited benefits from economies of scale beyond 25% market penetration. For CO_2 sequestration, some economies of scale are possible between the first two market penetration levels as pipeline length remains constant, but flow increases. However, as multiple production facilities become necessary, the number and length of pipelines increase and multiple sequestration sites become necessary. Moreover, there are limited economies of scale associated with injection wells and CO_2 compressors since the number of these components increase with market penetration. For this reason, although the cost per tonne carbon sequestered decreases slightly from 5% to 10% market penetration, it varies minimally as market penetration increases beyond these levels. The cost for CO_2 compression, transport, and storage ranges from \$13.90 to \$16.95/tonne C captured. The value for the transport-only component (~\$2.50/tC) is lower than the reported values since our pipelines are shorter than the generally assumed 100 km [48]. However, the values for compression and storage are consistent with the literature [1,48,49].

In examining distribution components, a large discrepancy exists between truck and pipeline distribution in the extent to which their components scale with market penetration. Fig. 6 illustrates how infrastructure requirements for each mode increase as market penetration increases. In the pipeline case, the length of both intracity and intercity pipes increases nonlinearly with market penetration. Specifically, as market penetration increases, the relative length of additional required pipeline decreases. For example, as market penetration increases 1400% from 5% to 75% market penetration, the length of intercity transmission pipelines increases only ~300%. The effect is less pronounced for intracity distribution pipelines because additional demand centers are added. Moreover, as market penetration and hydrogen transport increases, the pipelines increase in diameter. Given the length and diameter benefits, pipeline transport benefits greatly from economies of scale as market penetration increases. In contrast, truck infrastructure increases proportionately with market penetration. Thus, a 14-fold increase in market penetration requires ~1400% more trucks traveling a total distance that is ~1400% larger. Consequently, truck transport costs do not benefit from economies of scale.

The fact that liquefaction, liquid storage, and truck transport benefit minimally from economies of scale is reflected in the result that the total capital costs for the truck and pipeline cases converge as market penetration increases. For example, at 5% market penetration, the total capital cost for the truck case is about 19% lower than the cost for the pipeline case while, at 75% market penetration, the capital cost of the truck case is ~5% greater. The indication that the truck case does not continue to benefit from economies of scale is also evident in the cost per vehicle metric. As market penetration increases, this metric continues to decline for the pipeline case, but begins to level off at 25% market penetration in the truck case.

4.2.2. *Levelized cost of hydrogen*

Fig. 7 shows the levelized cost of infrastructure components at each market penetration level for both the pipeline and truck distribution cases. This figure indicates that the total levelized cost associated with the pipeline case continually declines as market penetration increases while the cost associated with the truck case levels off at 25% market penetration. This result is driven primarily by two factors: economies of scale in infrastructure components and differences in the share of annual costs contributed by operations and maintenance (O&M) versus capital costs.

At 5% market penetration, both infrastructure cases have similar total levelized costs of hydrogen and the costs associated with distribution components[7] account for ~45% of the total cost in both cases. In the truck case, liquefaction alone accounts for 40% of the total levelized cost. However, as market penetration increases, the contribution of distribution components to the total cost differs markedly for the two cases. In the pipeline case, the levelized cost of intracity and intercity pipeline distribution decreases as pipeline diameters increase and the quantity of hydrogen transported per kilometer of pipeline increases. At 75% market penetration, distribution's share of the total cost decreases to ~32% in the pipeline case. In contrast, liquefaction and truck distribution do not benefit from economies of scale as market penetration increases and, consequently, the contribution of these components to the total cost increases to ~50% at 75% market penetration.

Economies of scale in production contribute to decreases in the total levelized cost in both infrastructure cases until multiple plants are required at 50% market penetration.

[7] Distribution components include intracity and intercity pipelines in the pipeline case and LH_2 trucks, terminals, and liquefaction in the truck case.

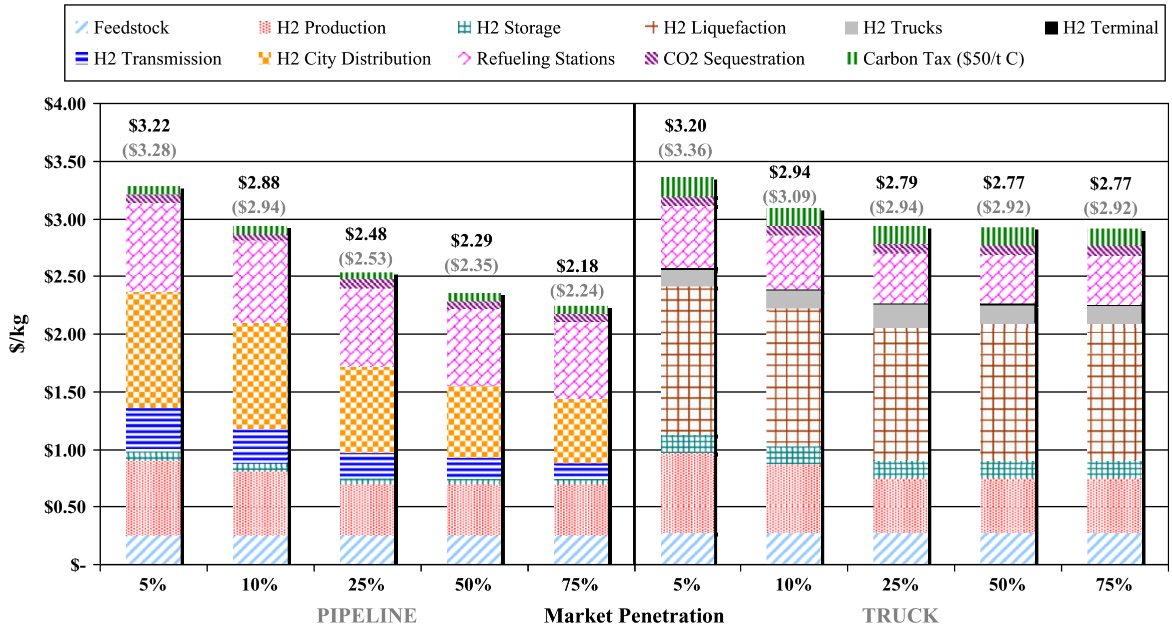

Fig. 7 – Levelized cost of hydrogen infrastructure components for the pipeline and truck distribution cases at all market penetration levels. Total levelized costs without carbon tax (with carbon tax) are listed.

Production-related economies of scale are primarily responsible for the decrease in the levelized cost of the truck case between 5% and 25% market penetration. Consequently, as multiple plants become required, the total levelized cost of the truck case levels off. In both infrastructure cases, the contribution of refueling stations to the total cost decreases as the number of intercity stations is reduced. The model also indicates that carbon sequestration infrastructure (including CO_2 compression, transport and storage), contributes very little to the total levelized cost of hydrogen (~3%).

Another reason why the levelized cost of hydrogen associated with the truck case does not decline as quickly as the pipeline case is because variable O&M costs (e.g., electricity and coal feedstock costs) occupy a large share of annual expenditures and typically do not decrease as a function of scale. Specifically, O&M costs account for ~55% of annual expenditures in the truck case, but only 45% in the pipeline case. The primary reason for the higher variable O&M costs is electricity purchases associated with the liquefaction of hydrogen for truck transport. This large use of electricity is also responsible for the fact that a $50/tonne carbon tax results in a larger cost increase in the truck case than the pipeline case if we assume that the electricity is not decarbonized. Since Ohio's electricity is supplied primarily by coal-fired power plants, significant CO_2 emissions are associated with electricity use in the state. As a result, the carbon tax increases the levelized cost of the truck case by 5–6% while the cost of the pipeline case increases only 2–3%.

In comparing the total levelized cost of hydrogen for each infrastructure case, Fig. 7 indicates that there is little difference (<2%) in the costs of the two cases at both 5% and 10% market penetration. However, as market penetration increases, the costs diverge and the pipeline case appears to represent the lower cost deployment strategy. In addition, if we assume that onsite production via steam methane reformation costs ~3.49/kg [28], the steady-state model suggests that centralized hydrogen production is preferable as early as 5% market penetration.

4.3. *Sensitivity analysis*

A sensitivity analysis was conducted to examine how changes in particular model parameters affect the tradeoff between infrastructure cases. The sensitivity analysis was performed at 10% market penetration since the costs associated with the infrastructure cases are similar at this level. For the pipeline pathway, we examined how changes in the fixed urban pipeline cost and pipeline capacity factor affect the levelized cost of hydrogen (Fig. 8). The fixed urban pipeline cost (baseline value = $600,000) is particularly influential as a 50% change in this value alters the levelized cost of the pipeline pathway by 15%. As a result, a small increase in this value can switch the preferred pathway from pipeline to truck at this market penetration level. The pipeline capacity factor (baseline value = 70%) is less influential, but a large decrease in this value (>50%) can result in a switch between pipelines and trucks.

For the truck pathway, four parameters were evaluated, including the maximum liquefier size, liquefier capacity factor, liquefier scaling factor, and truck unloading losses (Fig. 9). The estimate of the liquefier scaling factor has a large impact on cost since liquefaction occupies a large share of the overall cost associated with the truck pathway. Fig. 9 indicates that a small decrease (<5%) in the scaling factor can make the truck case competitive with the pipeline case. Likewise, a 17% increase in the liquefier capacity factor reduces the cost of the truck case so that it is comparable with the pipeline case. As the liquefier capacity factor increases, the size and number of

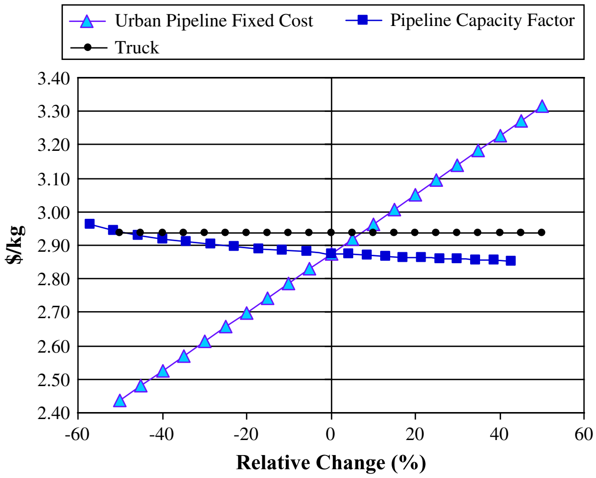

Fig. 8 – Sensitivity of levelized cost of hydrogen to pipeline parameters.

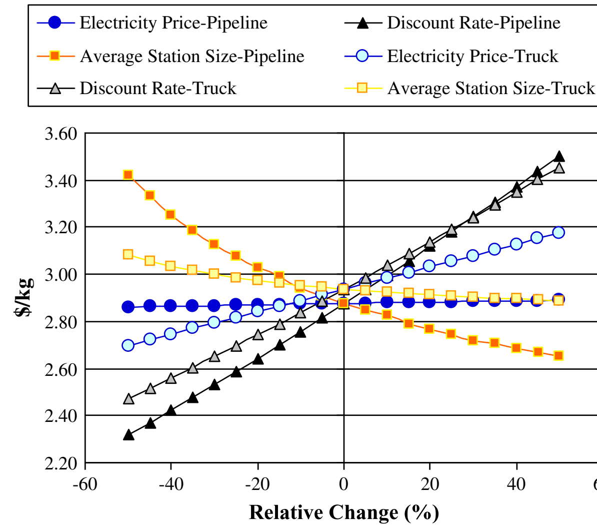

Fig. 10 – Sensitivity analysis for parameters that affect all pathways.

required liquefiers is reduced. The maximum liquefier size also has an effect, but does not cause a switch between distribution modes until the value is increased by more than 30%. Truck unloading losses are less influential, but a large decrease in this value can result in a switch from pipeline to truck distribution.

Several parameters that affect both distribution modes were also examined, including electricity price, discount rate, and average refueling station size (Fig. 10). An increase in the discount rate has a strong positive effect on the levelized cost of hydrogen. This affects the pipeline pathway most strongly since this pathway is very capital intensive. As a result, a moderate increase in the discount rate can result in a switch between distribution modes. A decrease in the average station size increases the levelized cost of both cases since more numerous and smaller stations are required. However, since pipeline-supplied stations cost more than liquid H_2 stations, the impact on cost is greater in the pipeline case. Consequently, a 10–15% decrease in the average station size can result in a switch from pipeline to trucks. Changes in the electricity price influence the truck pathway more strongly since significant electricity is required to liquefy hydrogen. As a result, a moderate decrease in the cost of electricity is required to make the truck case competitive with the pipeline case.

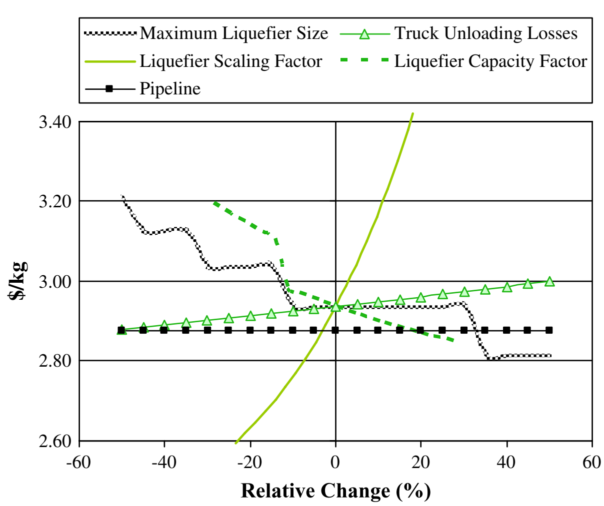

Fig. 9 – Sensitivity of levelized cost of hydrogen to truck pathway parameters.

5. Conclusions

This paper describes general methods for designing and evaluating regional hydrogen infrastructure deployment using detailed geographic data and technoeconomic models. The methods are applied to a case study in which coal-based hydrogen infrastructure with CCS is modeled for two distribution modes at various steady-state HFCV market penetration levels. Although the state of Ohio is studied, the methods are applicable to other regions and hydrogen supply pathways. The model results highlight several important findings regarding hydrogen infrastructure deployment in real geographic regions.

5.1. *Increased market penetration favors centralized production with pipeline delivery*

The results of the case study suggest that the levelized cost of hydrogen for the two infrastructure cases with different delivery modes is similar at 5% and 10% market penetration, but the pipeline case achieves the lowest cost at market penetrations greater than 10% (Fig. 11). A primary reason is the fact that the levelized cost of the truck case levels off above 25% market penetration while the cost associated with the pipeline case continues to decline at all penetration levels. Two reasons account for this difference in distribution modes. First, pipeline distribution benefits from economies of scale as the quantity of hydrogen carried per kilometer of pipeline increases as market penetration increases. In contrast, infrastructure components associated with LH_2 truck distribution

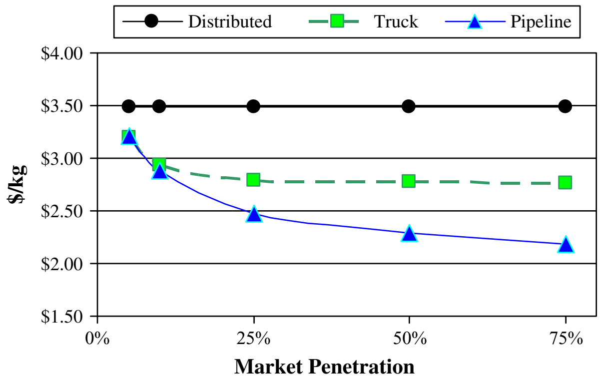

Fig. 11 – Comparison of the levelized cost of hydrogen for each infrastructure case.

achieve poor economies of scale since many components reach their maximum size at low statewide market penetration, requiring installation of additional units. Second, the truck case requires significant electricity for hydrogen liquefaction, resulting in large variable O&M costs relative to the pipeline case. Fig. 11 also indicates that centralized production achieves a lower cost than distributed production as early as 5% market penetration.

However, sensitivity analyses suggest that changes in specific parameters could change the results. In particular, assumptions about the electricity price, fixed urban pipeline cost, and parameters that impact liquefier cost are particularly influential on the result.

5.2. *A statewide perspective lowers the levelized cost of hydrogen*

In examining an entire state, 5% market penetration represents significant hydrogen demand (~266 tonnes/day), which serves about 440,000 hydrogen vehicles in Ohio. Because the statewide demand, which is distributed across multiple demand centers, is served by a single production facility, the cost of centralized production is relatively low compared with models that assume that each city is served by a dedicated plant. In fact, this model suggests that modeling infrastructure at the regional level allows for demand to be aggregated and economies of scale in production and distribution to be achieved at lower market penetration levels. As a result, this approach finds low levelized costs of hydrogen for centralized infrastructure.

The model also indicates that the capital investment to deploy hydrogen infrastructure for the state is relatively small. For example, in the pipeline case, ~\$1.6 billion is required at 5% market penetration while \$15.1 billion is required to serve the state at 75% market penetration. In addition, the results suggest that the cost of CO_2 sequestration adds very little to the total levelized cost of hydrogen (~3%).

5.3. *Coal-based hydrogen production with CCS could substantially reduce transportation-related CO_2 emissions*

The results indicate that fuel cell vehicles using centrally produced hydrogen with CCS and pipeline distribution could reduce CO_2 emissions 73% relative to advanced ICE gasoline vehicles. The truck case has a lower CO_2 reduction potential since significant electricity is required to liquefy hydrogen and high CO_2 emissions are associated with the current electricity grid mix in Ohio. However, the availability of decarbonized electricity would allow the truck case to achieve a substantial reduction in emissions. But decarbonized electricity would also result in higher electricity prices and, thus, would significantly increase the cost of hydrogen associated with the truck case. Consequently, CO_2 emissions can be reduced at a lower cost in the pipeline case and any regulations that increase the cost of CO_2 emissions (e.g., a carbon tax) will favor this distribution mode.

5.4. *Liquid truck delivery could significantly affect statewide electricity demand*

The energy efficiency metric indicates that centralized production with pipeline distribution is more efficient than distributing liquid hydrogen in trucks due to the electricity demands of liquefaction. In fact, liquefaction could increase statewide electricity demand by ~9% over 2002 levels when the market penetration is 75%. Furthermore, since the truck case requires significant electricity, it is highly sensitive to electricity prices, which may increase in the future. For this reason, the pipeline case presents less risk for hydrogen cost escalation from electricity prices.

5.5. *Future work*

This study presents preliminary insight into the design and costing of hydrogen infrastructure for real geographic regions. Although this model indicates relatively low costs for centralized hydrogen infrastructure, the steady-state model does not account for the underutilization of capital that would occur during a transition. For this reason, future work will focus on the introduction of time dependence to the model in order to include this effect, which will likely favor less capital-intensive pathways that can be deployed in more flexible increments (e.g. onsite production and centralized production with truck delivery).

Another issue with the current model is the fact that it evaluates only single infrastructure pathways over an entire region. While it does allow for comparison of these independent pathways, it does not provide an efficient platform for evaluating scenarios in which pathways change through time (e.g., from truck distribution to pipeline delivery) or through space (e.g., onsite production in remote areas and centralized production for large urban areas and clustered demand). We plan to explore techniques for examining mixed pathways in time and space in the future.

In addition, future work will include modeling of other regions to identify relationships between infrastructure cost and regional geographic characteristics. The number of hydrogen pathways will also be expanded in order to improve the understanding of the trade-offs between various production and distribution pathways. Specifically, we will examine centralized biomass gasification and large-scale steam methane reformation and electrolysis. Finally, we will update the techno-economic models as new information becomes available.

Acknowledgments

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