Modeling Deployment of Alternative Fuel Infrastructure in California Using GIS

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ABSTRACT

As California explores a potential transition to a hydrogen-based transportation system, an important step is to gain insight into the design and costs of a statewide infrastructure for producing and delivering hydrogen during this period. This paper describes GIS-based methods for optimizing the deployment of production, distribution, and refueling infrastructure as hydrogen vehicle market penetration evolves from 1% to 50% in California. Two particular modeling efforts are emphasized: 1) prediction of the spatial distribution of hydrogen demand at fixed market penetration levels and 2) optimization of hydrogen infrastructure to supply statewide demand via centralized hydrogen production with pipeline distribution or onsite production. The spatial model is combined with technoeconomic models of hydrogen infrastructure components to identify the optimal infrastructure design at each market penetration as well as the costs and CO_2 emissions of infrastructure deployment. This paper presents a GIS-based method for evaluating and designing alternative fuel infrastructure in a regional context.

1. INTRODUCTION

In the past few years, the pitfalls associated with our petroleum-based transportation system have become increasingly apparent. Between high oil prices, conflict in the Middle East, poor air quality, and deepening concerns about climate change, the motivation for moving towards clean and domestically available alternative fuels is growing. The most powerful driver for shifting the transportation system to a clean, low-carbon fuel in California is recent climate change policy.

In 2002, the transportation sector was the single largest source of anthropogenic greenhouse gas (GHG) emissions in California, accounting for approximately 40% of total emissions [1]. In contrast, the electric power sector accounted for only 20% of the total. For this reason, there has been significant legislative activity to address GHG emissions from the transportation sector, including a bill to restrict GHG emissions from motor vehicles (AB 1493) and a proposal to create a Low Carbon Fuel Standard (LCFS), which strives to reduce the carbon intensity of California's transportation fuel mix by 10% by 2020. Furthermore, the state has been a leader in pushing for cleaner vehicles through the Zero Emission Vehicle (ZEV) mandate and has committed to major economy-wide GHG reductions through the Global Warming Solutions Act (AB 32). AB 32 requires that the state's GHG emissions are reduced to 2000 levels by 2010, to 1990 levels by 2020, and to 80% below 1990 levels by 2050. In combination, this suite of legislation provides significant incentive for developing the technologies necessary to commercialize vehicles and fuels that can substantially reduce transportation-related GHG emissions.

One fuel that is particularly promising for addressing climate change, air quality, and energy security issues is hydrogen. Hydrogen is an energy carrier (like electricity) that can be produced from a multitude of primary energy sources, including fossil fuels (natural gas, coal, oil, etc.), biomass, and electricity (including renewable). The wide range of potential feedstocks allows for domestic production of transportation fuels and enhanced national energy independence. Moreover, hydrogen used in a fuel cell vehicle (FCV) emits only water vapor during operation, meaning zero emissions of criteria pollutants and GHGs during vehicle operation. However, despite the low emissions associated with vehicle operation, the lifecycle emissions associated with hydrogen are dependent upon how it is produced. For example, hydrogen generated from fossil fuels could result in high GHG emissions whereas wind-based hydrogen could achieve very low emissions. For this reason, it is important to consider the entire lifecycle when assessing the environmental benefits of hydrogen. Most importantly and unlike petroleum, hydrogen has the *potential* for low lifecycle emissions when coupled with a low-carbon production and delivery pathway.

However, despite the benefits of hydrogen, there are several major barriers to its deployment. First, further advances in fuel cell technology and hydrogen storage need to be achieved in order to allow FCVs to compete in the vehicle market. And, second, given the viability of the vehicles, a new and potentially expensive infrastructure will be required for producing and delivering the gaseous fuel. Furthermore, there is an inherent "chicken and egg" dilemma in that auto manufacturers are hesitant to release vehicles without the necessary infrastructure and fuel providers resist providing the infrastructure when there is uncertain vehicle demand. As a result, there has been extensive research documenting the potential costs of infrastructure components and pathways [2-7] and modeling how the infrastructure might evolve through time [8-10]. However, there has been limited research that uses detailed spatial data to analyze how a regional hydrogen infrastructure might develop in a real geographic region.

This paper documents methods for modeling regional hydrogen infrastructure deployment using a geographic information system (GIS). These methods are applied to a case study of a potential coal-based hydrogen transportation system in California with CO_2 capture and sequestration. The objective is to optimize hydrogen infrastructure design for the entire state at several steady-state hydrogen vehicle market penetration levels. GIS facilitates this analysis by allowing one to use existing spatially-referenced data, such as population distribution and existing infrastructure, to calculate the location and magnitude of hydrogen demand and optimize the placement of production facilities and transportation routes for moving hydrogen and carbon dioxide. Technoeconomic models that identify the costs and technical performance of infrastructure components allow for the calculation of the costs, energy usage and CO_2 emissions of different hydrogen infrastructure options. Based on these parameters, it is possible to identify the lowest cost infrastructure design for supplying hydrogen to users at each market penetration.

2. INFRASTRUCTURE CASES

In this study, two hydrogen production technologies, one distribution pathway, and four market penetration levels are modeled. The production technologies are centralized production using coal gasification and onsite production via steam methane reformation (Figure 1). The hydrogen distribution pathway for centralized production includes compressed gas pipelines. For each of these infrastructure cases, infrastructure is designed and evaluated at four steady-state[1] hydrogen FCV market penetration levels (5%, 10%, 25%, and 50%) in order to examine how the results might differ for early and more mature hydrogen markets. It is assumed that carbon dioxide (CO_2) will be captured and sequestered at each centralized coal gasification plant.

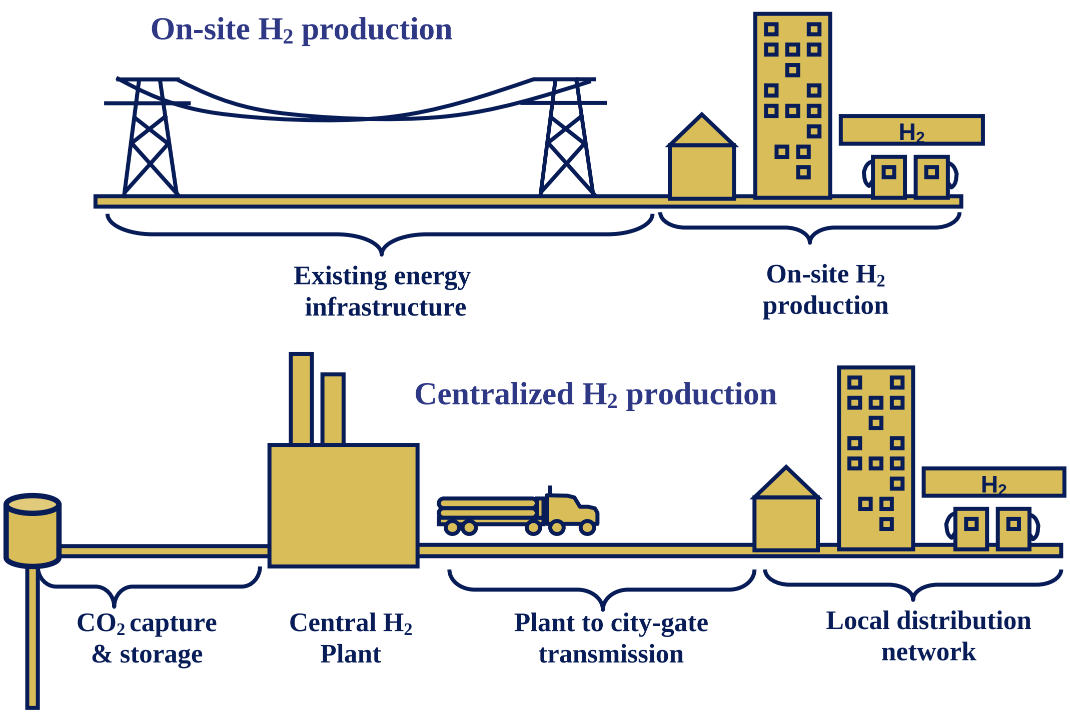

Figure 1: Schematics of onsite and centralized hydrogen production and delivery pathways

An optimized hydrogen infrastructure is designed for each infrastructure case and the costs, emissions, and overall energy efficiency of these cases are calculated and compared in order to identify the optimal infrastructure design in California at each of the

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[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.

four static market penetration levels. A mix of onsite and centralized production is allowed.

In evaluating each case, several simplifying assumptions are made: (1) infrastructure is optimized independently at each market penetration level (i.e., without regard for 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 organization so that economies of scale are most effectively captured.

3. METHODS AND MODEL DESCRIPTION

In order to model hydrogen infrastructure deployment in a specific region, both spatial data and technoeconomic models of infrastructure components are required. A geographic information system (GIS) facilitates infrastructure design by allowing one to use existing spatially-referenced data, such as population distribution, 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. Technoeconomic models that describe the costs and technical performance of infrastructure components allow for the calculation of the costs and CO_2 emissions of different hydrogen infrastructure options. Based on these parameters, the lowest cost infrastructure design for supplying hydrogen to consumers is calculated for each market penetration level. This paper will emphasize the GIS-based methods and will give only cursory review of the technoeconomic models.

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 and steady-state demand level. In this section, 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 [11], existing large power plants [12], existing pipeline rights-of-way [13], and potential CO_2 sequestration sites [14]. These datasets are illustrated in Figure 2. The US Census data is used to estimate hydrogen demand density based on population density. The existing power plants and pipeline rights-of-way are used to constrain the hydrogen infrastructure analysis by assuming that existing power plants will serve as potential sites for new coal-to-hydrogen facilities and hydrogen pipelines will follow existing rights-of-way. The use of existing datasets helps to constrain the number of possible distinct infrastructure designs, which improves the tractability of the optimization problem.

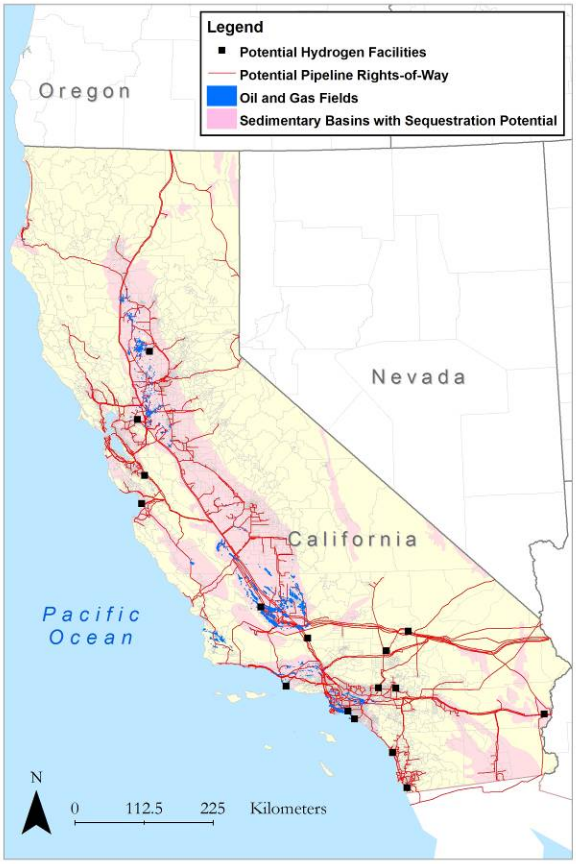

Figure 2: GIS datasets

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 [11]. This study examines steady-state (i.e., non-transition) market penetration scenarios in which demand is derived based on fixed percentages of statewide FCV penetration (e.g., 10% of existing light duty vehicles (LDV)). A custom tool, named the Hydrogen Demand Calculator, was developed in ArcGIS in order to automate the demand modeling process (Figure 3).

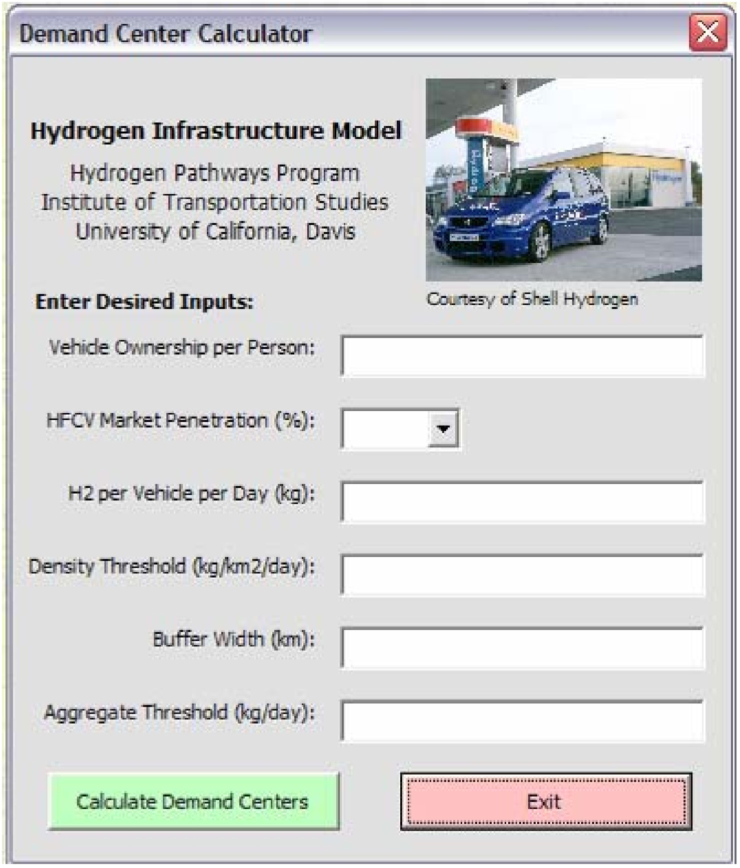

Figure 3: User interface for Hydrogen Demand Calculator

The following steps in the modeling process were completed at 1% FCV market penetration increments (from 3% to 60%) using the custom tool. First, census-derived population density, which is mapped at the census block level, is used to calculate hydrogen demand density[2] for each block (Figure 4a). Census blocks with high hydrogen demand density (defined as > 150 kg/km^2/day in this study) are then selected and buffers of five kilometers width are applied to them. All census blocks completely contained within the buffers are then selected in order to aggregate neighboring census blocks into demand clusters [15]. Given these demand clusters, the next step is to identify a subset consisting of clusters that have sufficient aggregate demand to support a single fueling station. To calculate aggregate demand, total hydrogen demand was identified for each census block by multiplying the demand per km^2 with the area (km^2) of each block. Aggregate demand for each demand cluster was then calculated by dissolving each cluster while summing the demand for all component blocks (Figure 4b). A threshold is

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[2] The equation for calculating hydrogen demand density is given as:
as: $HyDemand = PopDens \times VehOwn \times HyUse \times MarketPen$ 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 (# HFCV/# LDV). HyUse is calculated by assuming that the average annual mileage driven by a LDV is 12,000 miles and a FCV achieves a fuel economy about 2.5 times that of a current gasoline LDV (~57 miles per kg of hydrogen).

applied to retain only the clusters with sufficient hydrogen demand to warrant investment in infrastructure (defined as > 3,000 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 FCV penetration (Figure 4c).

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 FCVs. 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 four statewide market penetration levels considered in this study.

Table 1
Statewide market penetration scenarios

State-Wide Market Penetration	Market Penetration within Demand Centers
5%	7%
10%	12%
25%	28%
50%	55%

As we would expect existing demand centers to expand over time, methods were developed to ensure that demand centers identified in early markets are maintained in later stages. For example, at 10% market penetration, the extent of the demand centers at 5% market penetration should be maintained. To achieve this goal, we use ArcGIS Spatial Analyst to convert the demand centers from the current and previous stages to rasters using their identifiers as values. Next, we apply the cost allocation tool to assign each of the current cells to the nearest previous demand center value. The resulting raster is then converted back to a polygon and individual census blocks are reassigned to each demand cluster. Within each cluster, the blocks are then dissolved and a new aggregate hydrogen demand is calculated, which again must meet the minimum demand threshold of 3,000 kg/day.

The characteristics of the 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 portion of the statewide population in a relatively small fraction of the land area. For example, at 5% market penetration, 67% of the population resides in the demand centers, which occupy only 2.4% of the land area of California.

a) Population Density

b) Aggregate H_2 Demand in Demand Clusters

c) Final Demand Centers

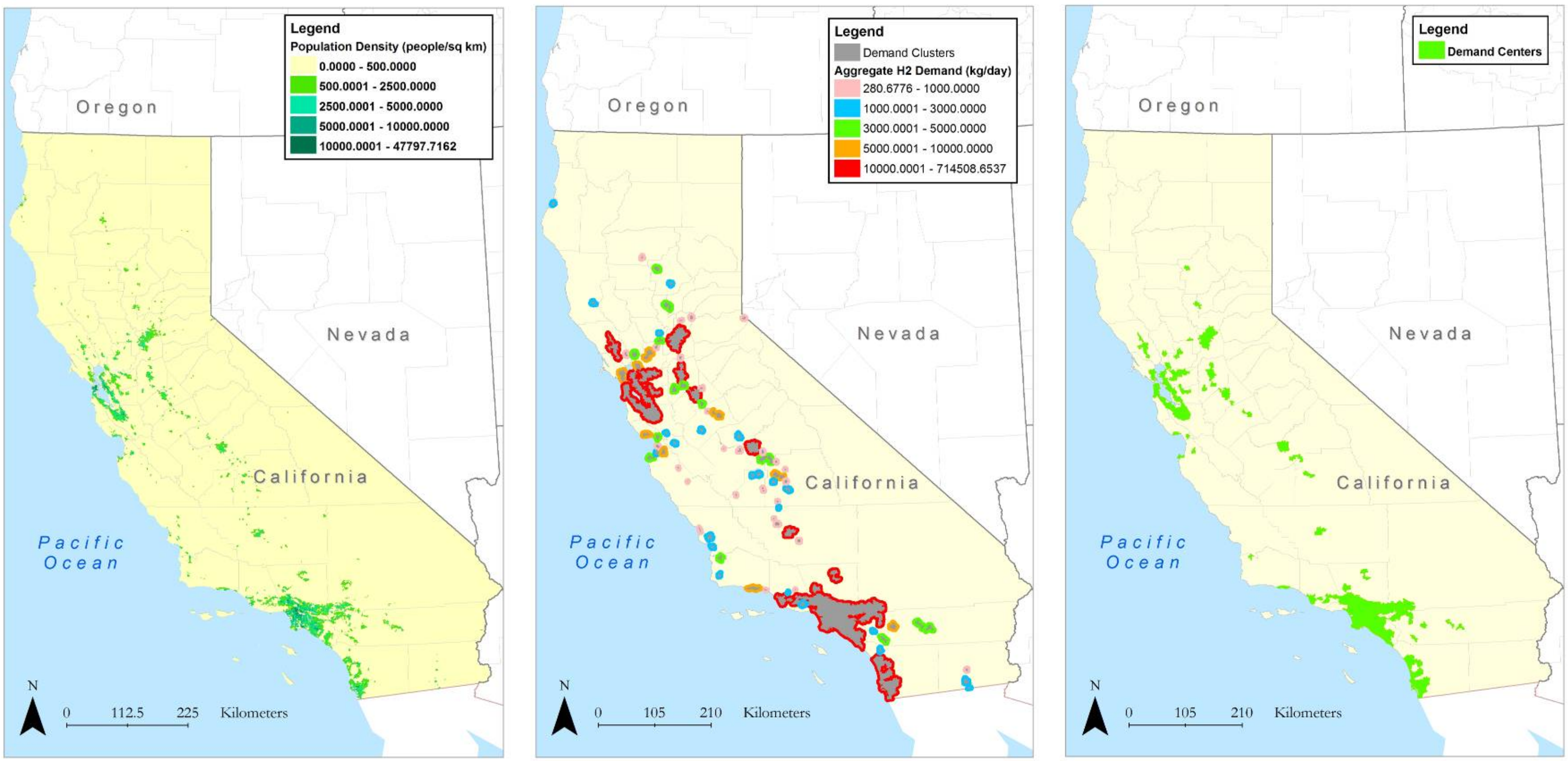

Figure 4: Demand modeling process at 10% market penetration

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%	26	67%	2.4%	679
10%	49	81%	3.7%	1,408
25%	72	88%	5.0%	3,561
50%	98	91%	5.9%	7,233

These methods provide a simple means for identifying potentially viable locations for hydrogen infrastructure investment at static market penetration levels. Additional criteria could be used to further refine the location of likely markets for hydrogen vehicles, including household income, number of registered vehicles, or local policies [16].

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 locations on which a fossil fuel-based power plant greater than 500 MW already exists. Each plant is assumed to have a maximum capacity of 2,800 tonnes of H_2 per day. According to the United States Environmental Protection Agency (US EPA) eGrid database, there are sixteen of these plants distributed throughout the state [12]. Given these potential facility locations, it is possible to identify the coal facility or facilities that minimize the cost of hydrogen delivery, which is determined by the total length of the pipeline network between the plant(s) and the demand centers.

In the pipeline case, existing pipeline rights-of-way from the California Energy Commission (CEC) are used to constrain the potential locations for hydrogen pipelines [13]. In order to assess the optimal pipeline network, a script in ArcView 3.x 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. Figure 5a shows the results of this analysis at 5% market penetration, where the lines indicate the shortest distance pathways and the black squares represent the potential production facilities. This network represents the portfolio of possible pipeline segments that connect coal facilities and demand centers at 5% market penetration. For each segment, the distance is calculated and then imported into a matrix in an Excel spreadsheet.

A minimal spanning tree optimization algorithm is then applied to identify the optimal pipeline network and production facility that minimizes the pipeline distance for delivering hydrogen to all demand centers. The iterations that are run for each coal facility are then compared 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 (> 10%

market penetration), additional plants are added that meet the remaining demand and minimize the additional hydrogen and CO_2 pipeline distances. Figure 5b shows the optimal supply network for the pipeline case at 5% market penetration.

(a) Shortest Distance Pathways Between All Coal Plants And Demand Centers

(b) Optimal H_2 Pipeline Network

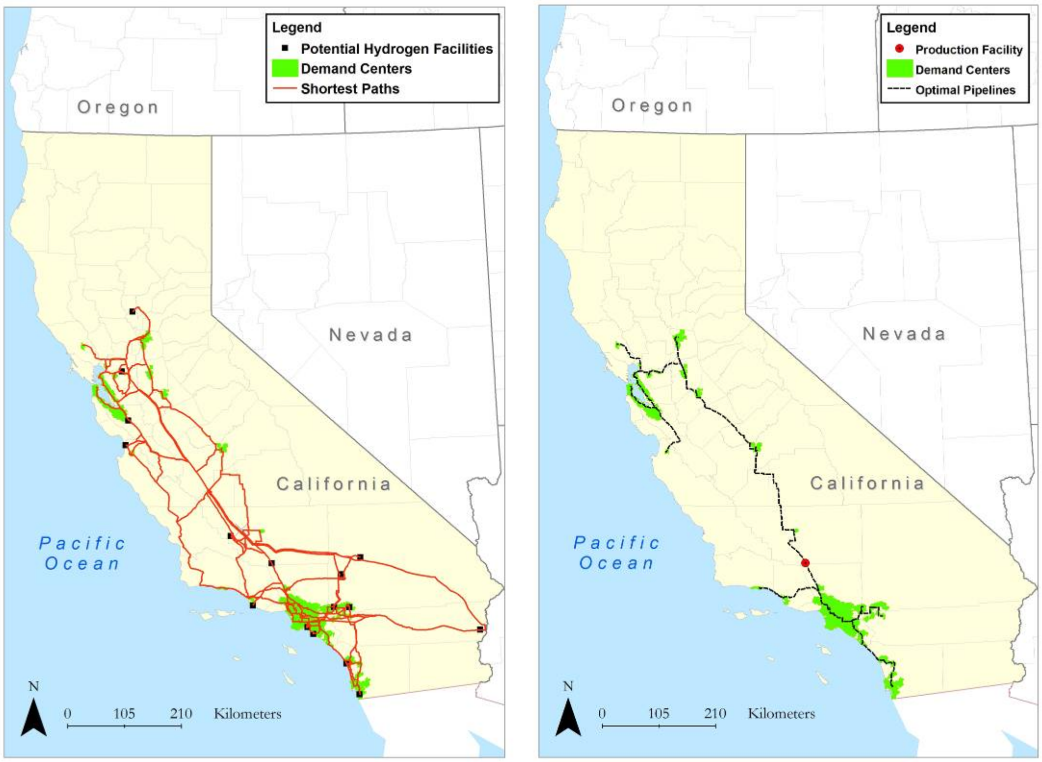

Figure 5: Pipeline network optimization at 5% market penetration

3.1.4. 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. The pipeline distribution distances determined in the previous section 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 [17] 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 (Figure 6a). Within this circle, it is assumed that the population distribution is homogeneous and the refueling stations are arranged along concentric rings and connected by pipelines (Figure 6b). As a result of this simplification, the distribution pipeline length can be estimated by the demand center area and the number of refueling stations.

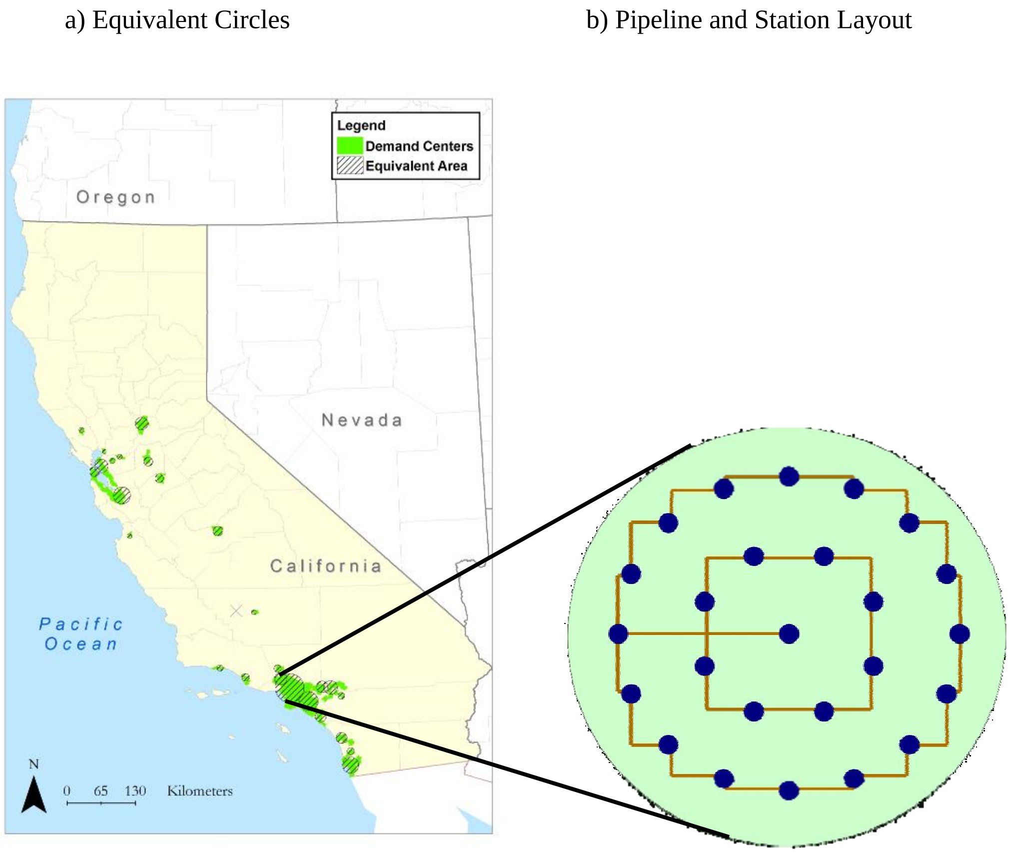

Figure 6: Idealized city model

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. [17] has shown that hydrogen provided at 10% of existing gasoline stations could provide adequate coverage. Assuming that existing gasoline stations serve approximately 3,000 vehicles per day [18], 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 3,000. The minimum number of hydrogen refueling stations is assumed to equal 10% of the total estimated gasoline stations [17]. Additional stations are only added when the average demand served by each station exceeds 2,400 kg/day (i.e., the maximum size station serves up to 4,000 hydrogen vehicles per day). If the maximum size is exceeded, an average station size of 2,000 kg/day is used to calculate the number of stations. Given the number of stations and area associated with each demand center, the intracity pipeline distances are estimated. Yang and Ogden [2] 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.

In the case of onsite production, the infrastructure is limited to refueling stations at which hydrogen is produced onsite. Consequently, centralized production facilities and pipeline networks are not required for these demand centers. Within each demand center, the size and number of refueling stations is calculated using the idealized city model as described above.

3.1.5. Optimizing Infrastructure for each Demand Center

In the previous sections, we have outlined methods for designing infrastructure for scenarios in which the entire state is served by a single hydrogen pathway using either onsite or centralized production. However, the optimal infrastructure design may involve a mix of pathways in which some remote areas are served by onsite production while areas with large or clustered demand are provided by centralized production with pipeline delivery. In order to identify the optimal pathway for each demand center, it is first necessary to quantify the cost of each complete pathway using technoeconomic models of hydrogen infrastructure components (discussed in next section). In the case of onsite production, we assume an average size for each station and, since stations can be built incrementally to meet local demand, the levelized cost of hydrogen ($/kg) is the same in each demand center as long as the average station size does not change. Consequently, at each market penetration level, a fixed levelized cost of hydrogen is used for onsite production at each demand center (~$3.50/kg).

In contrast, the cost of centrally produced hydrogen differs greatly between demand centers. In order to identify the levelized cost in each demand center, we allocate a portion of the total cost to each demand center based on its location relative to other demand centers and the size of its demand. Specifically, the following formula is used:

$$TC_{dc} = [(P_t + S_t + C_t)*(D_{dc}/D_t)] + (S*N_{dc}) + P_{dc} + T_{dc}$$

where TC_{dc} is the total annual cost allocated to a specific demand center, P_t is the total annual production cost, S_t is the total annual storage cost, C_t is the total annual CO_2 sequestration cost, D_{dc} is the daily hydrogen demand at each demand center, D_t is the total regional hydrogen demand, S is the average annual individual station cost, N_{dc} is the number of stations in a specific demand center, P_{dc} is the annual intracity (distribution) pipeline cost in a specific demand center, and T_{dc} is the annual intercity (transmission) pipeline cost allocated to a specific demand center. It is clear from the formula that the costs of centralized components (i.e., production, storage, sequestration) are allocated according to the size of demand in each demand center. Components that are derived from the idealized city model (i.e., stations and intracity pipeline) have costs specific to each demand center and are, thus, easily assigned.

However, transmission pipeline costs (T_{dc}) are more difficult to assign to each demand center. To achieve this, we use a matrix to determine the portion of each pipeline segment's flow for which each demand center is responsible. For each pipeline segment that flows to a given demand center, the hydrogen demand at the demand center is divided by the total flowrate through the pipeline. This allows us to assign the percent of each pipeline cost that should be allocated to each demand center. We multiply the percent allocation by the pipeline segment cost to assign costs for each pipeline and then add all the pipeline costs for each demand center to get a total transmission cost for each demand center. As expected, remote small demand centers (e.g., Arcata, CA) have high transmission pipeline costs while small demand centers that are en route to a large demand center (e.g., central valley cities along the major trunk pipeline) have low pipeline costs.

In order to calculate the levelized cost of hydrogen for each demand center, we divide the total annual infrastructure cost at each demand center by its annual hydrogen demand, or LC_{dc} ($/kg) = $TC_{dc}/(D_{dc}*365)$. Given the levelized cost of hydrogen at each demand center, we then compare it with the fixed levelized cost associated with onsite production. If the cost of the centralized production pathway is greater than the onsite pathway, this suggests that onsite production is more appropriate for this site. We then remove all demand centers that are better served by onsite production and recalculate the cost of centralized infrastructure for the remaining demand centers. It is possible that the removal of some demand centers will cause the cost of hydrogen in some remaining demand centers to increase as they are allocated a larger percentage of the transmission pipeline costs. Consequently, the second iteration may identify new candidates for onsite production. The process is iterated until a stable set of demand centers is identified. At this point, an average levelized cost of hydrogen is identified for the entire region, including both onsite and centralized production pathways.

3.2. Technoeconomic Models

Once the optimal infrastructure design (i.e. plant location, distribution layout, and sequestration site) has been determined, the GIS allows us to map and quantify the extent of infrastructure components required. Technoeconomic models for each of the infrastructure components are then used to determine the cost and technical performance 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. Interested readers are encouraged to see a forthcoming publication by the authors for a summary of the key references and assumptions used in the technoeconomic analysis [19].

4. METRICS AND RESULTS

Given the optimized infrastructure design for each scenario, three metrics are evaluated and compared: (1) levelized cost of hydrogen, (2) capital cost of hydrogen and CO_2 infrastructure, and (3) 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[3]. Estimation of infrastructure capital costs are important

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

for indicating the total investment needed to build the system. CO_2 emissions is an important metric to consider since it indicates the climate change impacts associated with the hydrogen pathway. Since CO_2 emissions (g/mile) vary minimally with market penetration, this metric is summarized at 25% market penetration in the first section. In the remaining sections, infrastructure design and cost is outlined for each market penetration level.

4.1. CO_2 Emissions

For calculating CO_2 emissions, we use 0.471 kg CO_2/kWh for electricity related emissions [12], 91.7 kg CO_2/mmBtu for coal related emissions [20], 13.3 kg CO_2/kg H_2 for onsite production stations, 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. Figure 7 compares CO_2 emissions for each infrastructure case. Emissions for advanced gasoline internal combustion engine (ICE) vehicles are provided as a reference.

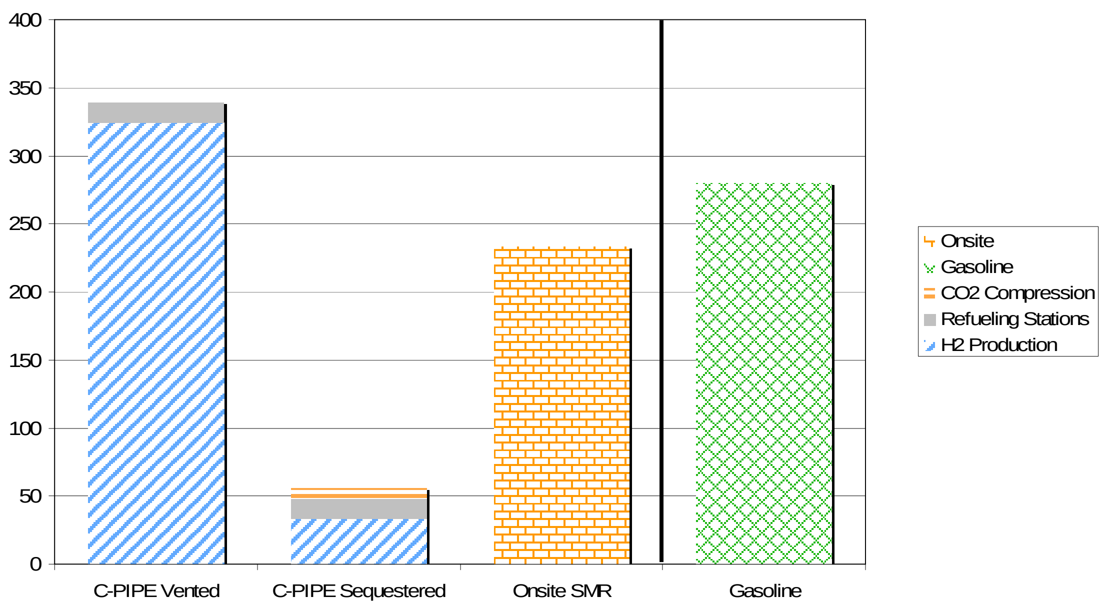

Figure 7: CO_2 Emissions of Hydrogen Infrastructure Cases (C-PIPE = Coal with Pipeline Delivery)

This figure illustrates the importance of capturing emissions from coal production facilities since the case in which the CO_2 is vented results in a 21% *increase* in well-to-wheels CO_2 emissions for FCVs relative to gasoline vehicles. However, with carbon capture and sequestration (CCS) at the coal plant, emissions associated with hydrogen production decrease dramatically, resulting in an 80% *decline* in emissions relative to gasoline. Since CO_2 is not sequestered at refueling stations with onsite production, this pathway achieves a moderate 17% reduction in CO_2 emissions. It is clear that coal-based hydrogen production with CCS coupled with hydrogen FCVs can achieve significant reductions in CO_2 emissions relative to gasoline vehicles.

4.2. Hydrogen Infrastructure Design and Cost

The optimized infrastructure design, associated capital cost, and levelized cost of hydrogen are quantified and mapped at each market penetration level.

4.2.1. Infrastructure Design and Capital Cost

Regional hydrogen infrastructure deployment is optimized at each market penetration level and includes both onsite and centralized production. Figure 8 presents the infrastructure design for the pipeline case at each market penetration level. These figures illustrate how hydrogen infrastructure might grow to meet increasing demand. In the 5% case, the pipeline network is relatively simple with service to the twenty-six most populous cities in California. As market penetration increases, the demand centers both grow in size and multiply in quantity as more cities become viable demand centers. At 50% market penetration, an elaborate pipeline network spans the majority of the state and hydrogen demand is sufficient to require four hydrogen production facilities. Even at 50% market penetration, it is still not economical to supply hydrogen via pipeline to some remote cities. Ten cities representing about 1% of hydrogen demand are served by refueling stations with onsite hydrogen production via steam methane reformation (Table 3).

Table 3
Distribution of Demand Centers Served by Centralized vs. Onsite Production

State-Wide Market Penetration	Demand Centers Served by Centralized	Demand Centers Served by Onsite	% of Demand Centers Served by Onsite	% of Hydrogen Demand in “Onsite” Demand Centers
5%	23	3	11%	1.9%
10%	37	12	24%	3.8%
25%	64	8	11%	1.0%
50%	88	10	10%	0.7%

Table 4 summarizes the total capital costs of the infrastructure required at each market penetration level. These costs are not cumulative, but rather indicate the total costs required to build the infrastructure at a particular static market penetration level.

Table 4
Regional Infrastructure Capital Costs

State-Wide Market Penetration	Capital Cost ($Billion)
5%	3.42
10%	6.05
25%	13.3
50%	24.7

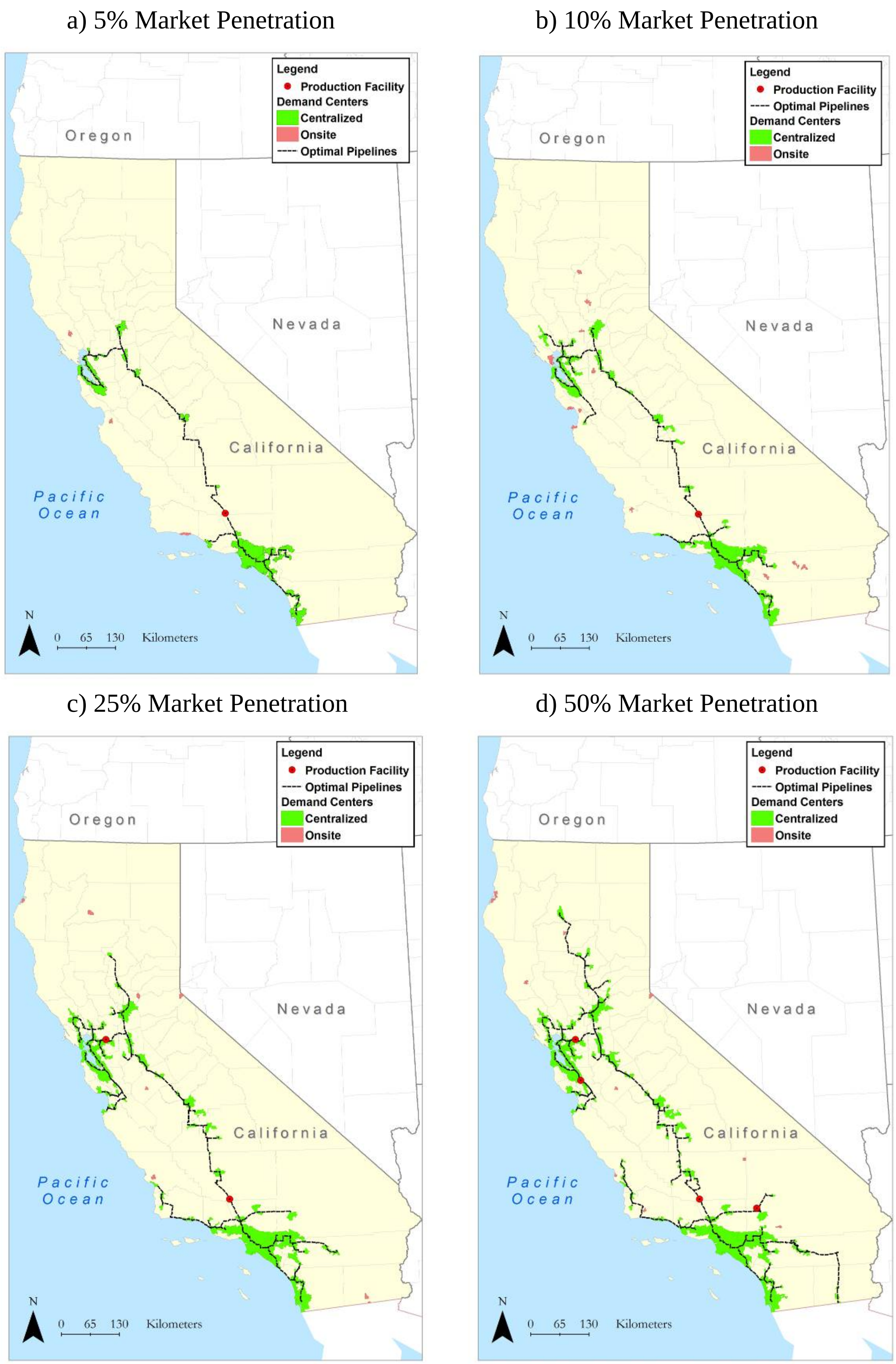

Figure 8: Optimized hydrogen infrastructure design at each market penetration level

4.2.2. Levelized Cost of Hydrogen

Figure 9 shows the levelized cost of infrastructure components at each market penetration level. This figure indicates that the total levelized cost continually declines as market penetration increases. This result is driven primarily by economies of scale in infrastructure components.

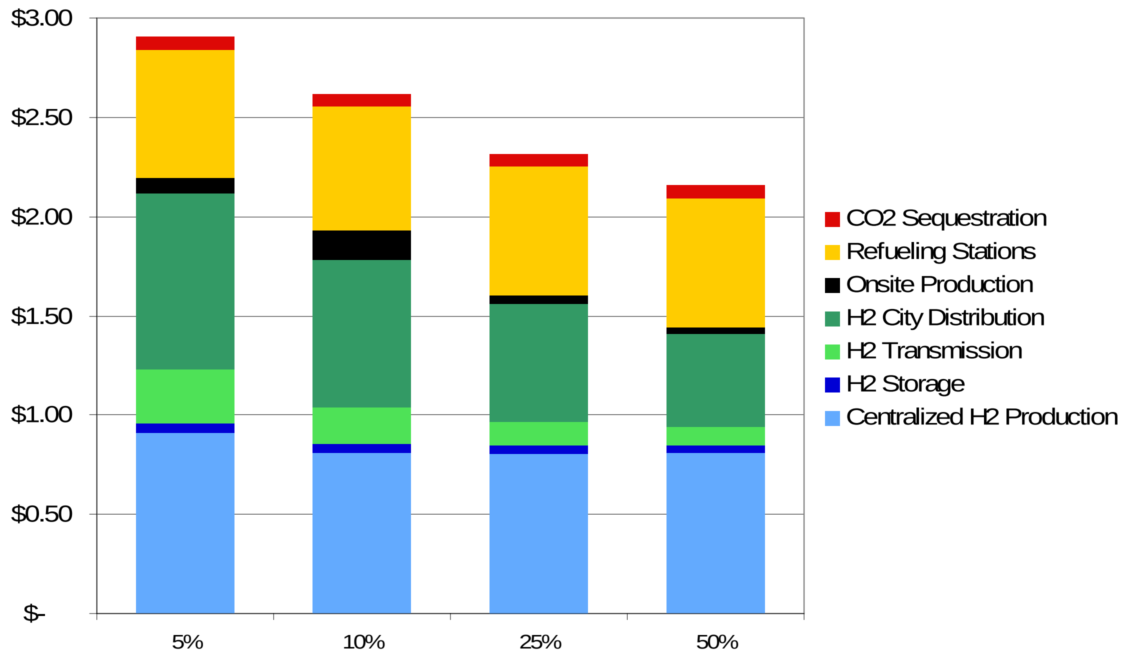

Figure 9: Levelized Cost of Hydrogen Infrastructure Components at All Market Penetration Levels

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. 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.

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 and pipeline delivery is modeled at various steady-state FCV market penetration levels. Although the state of California is studied, the methods are applicable to other regions.

The use of GIS facilitates the spatial modeling of regional infrastructure deployment by providing several valuable tools. First, it enables us to model the location and quantity of demand for a specific commodity as it grows over time by examining the distribution of specific population demographics. Second, it allows us to identify potential locations for infrastructure based on the locations of similar existing infrastructure, including pipeline rights-of-way and large power plants. Third, we are able to model optimal distribution networks and production locations using the GIS. Fourth, given our optimal design, we can quantify the extent of required infrastructure so that more accurate estimates of cost can be obtained. Finally, we are able to visualize the optimal design(s) in order to better communicate what the infrastructure might look like through time, including which areas will be served and the potential impacts of the system.

This paper describes one method for designing an infrastructure for hydrogen fuels in a specific geographic region. However, the model needs improvement in several areas. First, we would like to incorporate a dynamic component to the model so that we can examine how an infrastructure might grow through time, including transitions between production and distribution modes. The pipeline model also needs improvement in order to optimize the network based on flow and distance (i.e., minimizing total cost) rather than simply minimizing distance. We welcome any comments and direction that others working in the field of infrastructure design can provide.

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Please contact Nils Johnson at njohnson@ucdavis.edu with questions and comments.

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