ANALYZING NATURAL GAS BASED HYDROGEN INFRASTRUCTURE – OPTIMIZING TRANSITIONS FROM DISTRIBUTED TO CENTRALIZED H_2 PRODUCTION

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1. INTRODUCTION

Hydrogen offers a wide range of future environmental and social benefits, when used as a fuel for applications such as light duty vehicles and stationary power. These potential benefits include significant or complete reductions in point-of-use criteria emissions, lower life-cycle CO_2 emissions, higher end-use and life-cycle efficiency, and a shift (with respect to transportation fuels) to a range of widely available feedstocks [1-3]. Despite the potential benefits of a hydrogen economy, there are many challenges as well. One of the most critical is the tremendous cost and investment associated with developing and transitioning to an extensive transportation network based upon hydrogen. The widely-discussed "chicken and egg" problem focuses on the difficulty in building vehicles and hydrogen supply to meet a small and growing demand. While many current studies of the 'Hydrogen Economy' present a steady-state portrait of a mature energy system including H_2 production, distribution and utilization [4-7], the transitional issues that are embodied in the chicken and egg problem are not addressed. Modeling the transition to a hydrogen economy is more complex than these static analyses because of dynamic nature of the problem. The transition costs will be determined by the size of the production, distribution and other infrastructure components and the economies of scale associated with these components and with the major shift in the transportation sector. Some analysts believe that in the near-term, infrastructure will be built up by means of distributed production of hydrogen at refueling stations by fuel processors or electrolyzers, which will lessen the initial infrastructure investment [8]. These systems take advantage of existing energy distribution infrastructure (natural gas and electricity) reducing the capital expenditure requirements for hydrogen infrastructure. Only after significant maturation and market penetration of vehicles will the hydrogen demand be large enough to take advantage of the economies of scale associated with a dedicated infrastructure with large centralized hydrogen energy production plants and hydrogen pipeline distribution [4, 7, 8]. In general, there is a trade-off between production costs and distribution costs that impacts a decision when to move from distributed to centralized hydrogen production. One key question that this analysis will explore is when and under what circumstances this transition could occur.

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Hydrogen Production via Natural Gas Steam Reforming

Steam reforming of natural gas is the most common method of industrial and refinery hydrogen production today. Over 95% of hydrogen production in the US uses natural gas as the primary energy feedstock. Current hydrogen uses include ammonia synthesis, methanol production, refinery applications, food processing, and fuel for the NASA Space Shuttle main rocket. Often these large-scale production facilities are located at the point of use, such as refineries and ammonia synthesis plants. There is also a limited merchant hydrogen delivery infrastructure that would need to be greatly enhanced in order to distribute centrally produced hydrogen to a network of refueling stations in cities. Small natural gas steam reformers are currently being developed by a number of companies for stationary fuel cell and hydrogen refueling station applications. While not as cost-efficient as large reformers on a per kilogram basis, but they permit the reduction in large fixed costs associated with building the production and distribution infrastructure to supply H_2 to refueling stations that will be greatly underutilized in the early transition to a hydrogen economy.

Natural gas is an excellent early feedstock for hydrogen production from an economic and engineering standpoint, but the production of hydrogen from natural gas for use in transportation will provide relatively modest societal benefits over the use of petroleum. Life cycle greenhouse gas emissions from a fuel cell vehicle using NG-based hydrogen would not provide the dramatic (>50%) GHG emissions reductions needed for climate stabilization unless carbon sequestration processes are also used. Studies have shown that H_2 produced from NG and used in a FCV will have a well-to-wheels (WTW) GHG emissions reduction of 10-40% from those of a gasoline ICEV [7, 9, 10]. Similarly, transitioning to hydrogen will allow for displacement of petroleum imports and subsequently may increase geopolitical security, but natural gas will be an increasingly imported fuel as demand continues to rise in the US. As a result, natural gas based hydrogen production at the distributed and centralized scale should be thought of as a useful *transition* strategy (albeit an elegant one) for the development of a hydrogen infrastructure and hydrogen fuel cell vehicle deployment. Achieving the maximum benefits of hydrogen, which will come in the long term, require the use of renewable and carbon-free domestic resources [2, 7].

Scope of Paper

The Hydrogen Pathways Program at the Institute of Transportation Studies at UC Davis (ITS-Davis) is examining many aspects of a transition to large-scale use of hydrogen in transportation [11] and this paper is a small but representative piece of much of that larger suite of work to analyze the transitional aspects of building hydrogen infrastructure. This paper presents results from a simplified replacement model, Transitional Hydrogen Economy Replacement Model using Natural Gas (THERM-NG), for understanding hydrogen infrastructure transitions, including the following model components:

- Central plant natural gas steam methane reforming (SMR) –includes hydrogen production and storage at a central location.
- Idealized city hydrogen distribution network - develops an idealized city where the number and location of refueling stations is varied to investigate the distance between users and the nearest stations and the length of the hydrogen distribution network to supply the stations.
- Refueling station – includes components such as hydrogen storage and dispensing as well as an option for on-site H_2 production from distributed natural gas SMR.

These infrastructure components are tied together to create a hydrogen supply pathway for an idealized city. Exogenous demand profiles and assumptions about the population, size and location of the city are specified as model inputs. The model tracks the economics and environmental impacts of the infrastructure development necessary to meet the demand for hydrogen in this city. Though THERM-NG only includes two potential pathways with one feedstock, it encompasses the two broad classes of hydrogen production (distributed and central) and can yield some important insights into hydrogen infrastructure transitions, specifically regarding issues related to infrastructure technology lock-in. Understanding if and when the transition makes economic sense and the factors that will influence that transition can help guide efficient decision making for policy, research and development directions and investments by government and industry.

2. THERM - MODEL AND METHODS

2.1 Modeling approach

The Transitional Hydrogen Economy Replacement Model (THERM) integrates several infrastructure components (see Figure 1) to determine the costs associated with the transition from distributed to central production. Each of these components (demand profiles, central plant, pipeline distribution system, and refueling stations with and without on-site production) is modeled in an Excel spreadsheet. THERM is written with Visual Basic as the model framework to integrate components, size equipment to ensure the infrastructure capacity is sufficient to meet demand each year, and aggregate costs and emissions of whole pathways over time. The annual demand is specified by exogenous demand profiles that can be specified by the user. In each model year, the annual hydrogen demand is passed to the individual infrastructure components (hydrogen production, pipeline distribution and refueling stations) to determine the costs, energy use and CO_2 emissions associated installing and operating these systems. If the existing supply from the previous year is not sufficient to meet the current demand, additional infrastructure will be added (e.g. central plants, pipelines and refueling stations) to meet the increased demand. At the specified transition year, the distributed hydrogen production infrastructure will be replaced by a centralized hydrogen infrastructure. The goal is to analyze how the hydrogen cost and performance metrics vary for different assumptions about the transition time, demand growth rates, city population and size. Each of the infrastructure model components is described in more detail in the sections below.

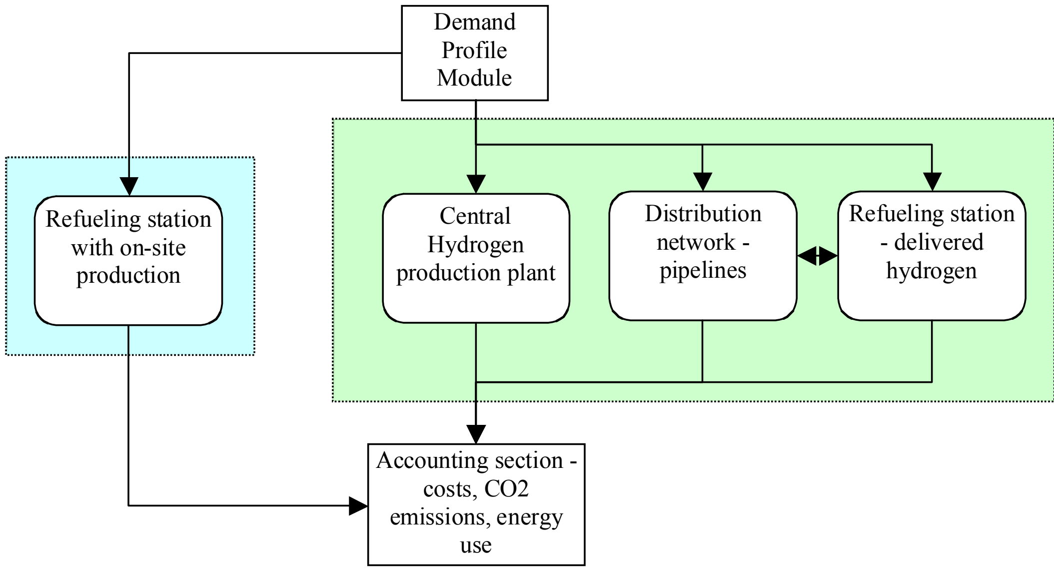

Figure 1 Schematic of Transitional Hydrogen Economy Replacement Model (THERM) components and their interaction for distributed and centralized hydrogen production.

2.2 Hydrogen demand

The hydrogen demand profile for a particular city is a function of specific input parameters including city size, number of vehicles, market penetration rate of H_2 vehicles over time, and H_2 usage per vehicle (fuel economy and vehicle miles traveled). Table 1 shows some of the assumptions used to derive the H_2 demand. A number of reasonable market penetration profiles are specified exogenously to the model according to input scenarios that are broadly classified by the shape of the curve (linear vs logistic) and rate of growth (see Figure 2 for the four demand growth rates). Logistic functions are used to simulate typical market penetration and growth. The demand profile specifies the rate of change of the number of vehicles that will run on H_2 and assuming a fuel usage for these vehicles, the hydrogen demand for the entire city. The spatial distribution of hydrogen demand is assumed to be uniform throughout the network of stations. These demand profiles are inputs to the supply portion of the model, which calculates the costs of building infrastructure to meet or exceed this demand. The demand is specified for a city that has a specified population, number of vehicles and refueling stations.

Table 1. Assumptions for hydrogen demand estimation for transportation vehicles

Vehicles per person	0.7 vehicles/person
Miles driven per vehicle (fleet average)	12000 miles/yr
FCV fleet average fuel economy	55 miles/kg (55 mpgge)

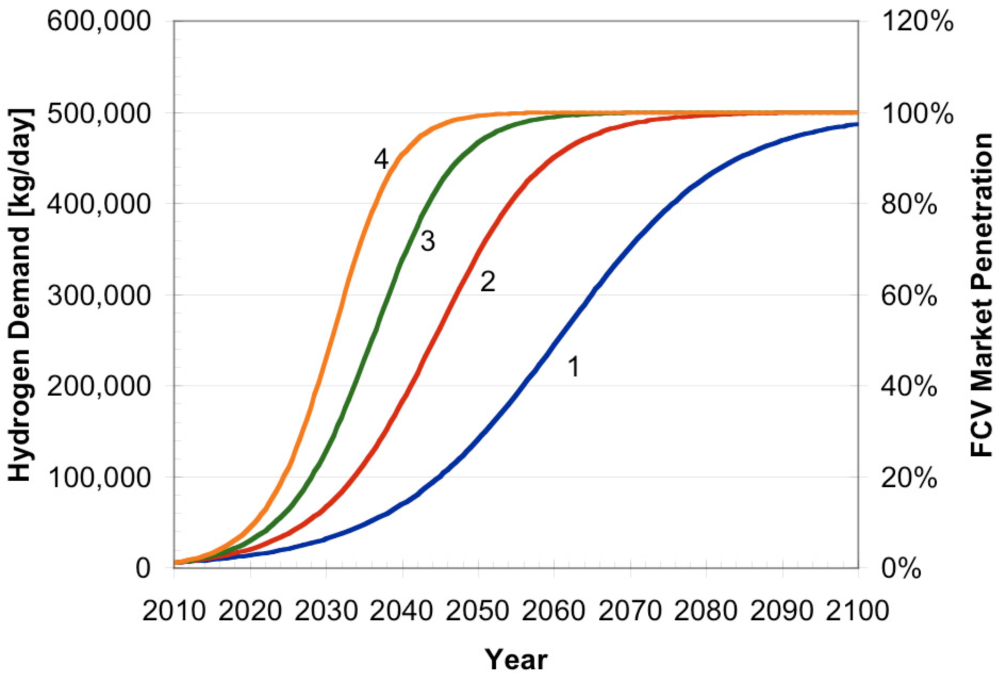

Figure 2 The four hydrogen demand "logistic" profiles used as inputs for THERM-NG for a city population of 1 million.

2.3 Central natural gas production plant

Plant Design

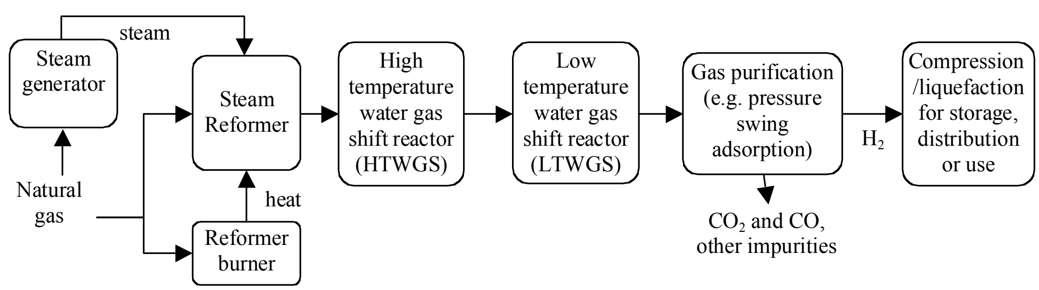

Figure 3 Schematic of central-scale natural gas steam reformer components

Natural gas is currently the lowest cost hydrogen production method, supplying around 95% of hydrogen in the US. The hydrogen production process is broken into three steps (reformation, water gas shift and separation). These three reactions are used to strip the H_2 from the natural gas molecules, enhance the yield of H_2 by further extracting enthalpy from carbon monoxide (CO), and purifying the H_2 and reducing the impurity (mainly CO and CO_2) concentration. The system components for the natural gas to hydrogen plants are shown in more detail in Figure 3, and include a steam methane reformer, which requires input natural gas, steam and heat, two water gas shift reactors, a gas separation system to yield high purity H_2, and compression or liquefaction for storage and distribution. Large-scale natural gas production plants can range in size from 10,000 kg/day to 2,500,000 kg/day. Despite the mature technology for production and separation, the US Dept. of Energy has identified technology gaps where R&D (specifically membrane technologies) can further reduce costs and improve efficiency.

Costs

A number of cost studies [6, 7, 12, 13] have estimated or reviewed the costs of large scale natural gas systems. These costs (shown in Table 2) are based upon studies from Ogden and SFA Pacific.

Table 2. Cost Assumptions for Central Hydrogen Plant - Natural Gas Steam Reforming and Compression

Capital cost equation (C_x is the capital cost for a plant of size x (S_x)).	$C_x = C_b\left(\frac{S_x}{S_b}\right)^{\alpha}$
Base Capital Cost (C_b)	$192 Million
Base Plant Hydrogen Production (S_b)	500 tons/day
Scaling factor (α)	0.70
Central Plant Storage	50% of daily production
H_2 gas storage costs (separate from plant costs)	$250/kg
Other startup Costs (Land, Engineering, etc.)	51% of capital
Natural gas feedstock cost (central plant)	$5.00/MMBTU
Non-fuel O&M	6% of Installed Capital

Integration into THERM

One important consideration for THERM is the installed central plant size in the transition year. During a transition to hydrogen, the demand will increase on an annual basis, and the plant will need to be sized to handle the demand growth without adding capacity too frequently. There are economies of scale for capital equipment (i.e. diminishing cost increases for larger capacity plant components) that encourage larger plant capacities, while utilization of capital equipment is a crucial issue because underutilization leads to higher hydrogen costs. Thus, there is a tradeoff for building large production plants and the optimal size will be a function of the equipment economics and the timing and size of hydrogen demand. The specified annual hydrogen demand will determine the annual utilization of the plant and determine most of the operating, energy and fuel input costs for the plant. The remaining costs, i.e. capital recovery and other fixed costs, are independent of plant output. In general, the central hydrogen plants will be underutilized over a significant fraction of the model years.

A number of scenarios are run where the central plant is built in different size increments, including 33%, 50% and 100% of the final city hydrogen demand. The variation in plant size allows for different levels of average plant utilization, which depending upon the trajectory of the demand profiles and other factors, can lead to changes in the optimal transition year and lowest cost pathway. The capital, installation, and operating costs are recorded on an annual basis and are summed with other hydrogen infrastructure costs (described below) to determine levelized hydrogen costs. Alternate uses for the hydrogen, such as electricity production or chemical synthesis and refining operations may increase the utilization of central plant hydrogen, but these are not considered in this paper.

2.4 Hydrogen distribution

Idealized city models

The distribution of hydrogen from a production facility to refueling stations is an important component of a centralized pathway and can account for a significant fraction of the total costs, emissions and energy input of delivered hydrogen. For generic hydrogen infrastructure models, it is necessary to get an estimate of the pipeline length or truck travel distances for connecting a network of refueling stations in order to estimate costs and other aspects of this distribution. The use of generalized, idealized city models can provide information about these system parameters for a wide range of cities with specified characteristics. There are a number of different configurations for a network of refueling stations [4, 14]. Even for the same number of refueling stations distributed throughout a city, the length and subsequent cost of the distribution network can vary significantly depending upon how those stations are arranged. The goal of this model component is to develop some generalizations and abstractions with which to characterize a generic city in terms of its size, hydrogen demand and the resulting hydrogen infrastructure required to support this demand. The model component assumes that the city is circular, city size and population are not specified absolutely, population distribution is homogeneous, and distances are characterized as a function of the city radius and follow a grid (i.e. rectilinear) road network. The lack of detailed specification of physical size and population allows application of the results to different sized cities. A detailed geographic study of a specific city/region using GIS [15] can yield very detailed information. However, the simplified city permits the development of "rules-of-thumb" and equations that can relate numbers of stations and city size with the length of distribution networks which are generically useful and can be quickly applied to a new location in the way that a detailed analysis cannot.

For the purposes of applying the idealized city distribution model to THERM, the criteria of maximizing consumer convenience is used. This means that, given the homogenous population distribution, the refueling stations will also be evenly distributed throughout the circular city. This distribution minimizes the average travel distance that consumers must travel to their nearest station. Distribution network lengths and travel distances are given as a function of the city radius. Pipelines lead to significantly lower distribution distances than trucks for large numbers of stations in the networks. It is assumed that trucks will travel from the starting point at the city gate to each station individually (leading to many overlapping truck routes), while distribution pipelines connect each station to other stations.

This is shown in Figure 4, which plots the results of minimizing the travel distances for consumers in a city with a homogenous population distribution. The pipeline length ($L_{pipeline}$) is a power law function (with exponent of ~0.5) of the number of stations, while the truck route distance scales linearly with the number of stations. Thus as the number of stations grows, the pipeline distribution modes become more efficient than trucks. The model results are plotted to compare length of the pipeline network or truck driving distance as a function of the number of stations.

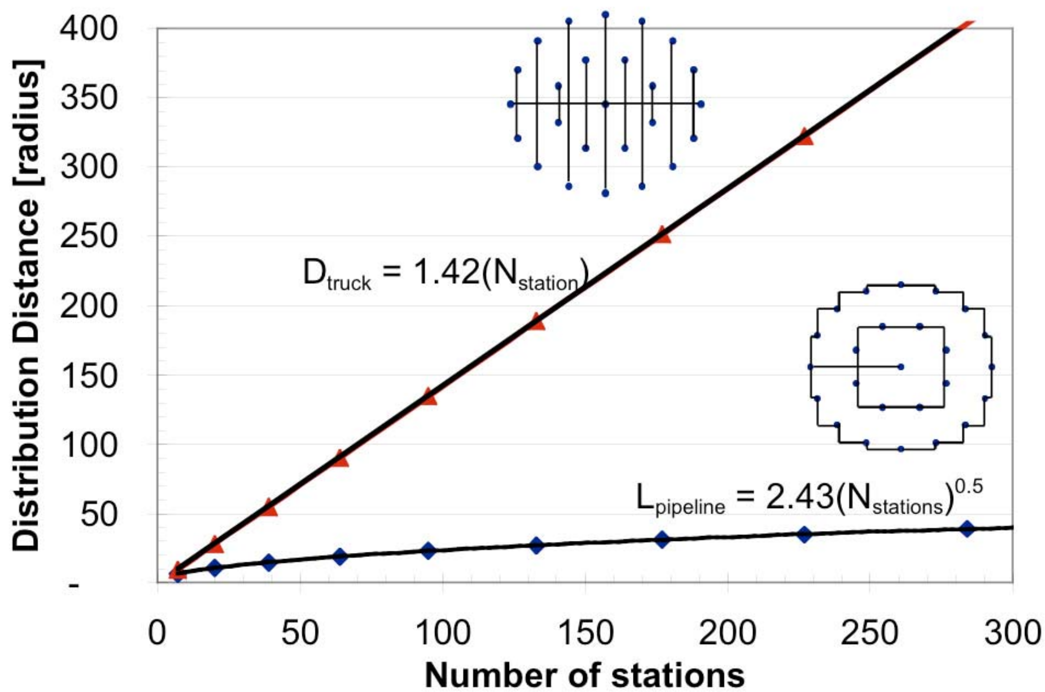

Figure 4 The relationship between the number of stations within the city and the total delivery distance for pipelines and trucks.

The idealized city model is used within the THERM-NG model to estimate the length of distribution pipeline required for a city with a specified number of stations. The assumption of a homogenous population distribution, rectilinear travel, and maximization of consumer convenience leads to a conservative estimate for the length and cost of the pipelines.

Determining Number of Refueling stations

The length of the pipeline network to supply hydrogen to refueling stations depends on the number of stations. The number of stations is determined by the total hydrogen demand for the city and the station size. One key assumption in THERM is that the number of hydrogen stations (or fraction of existing gasoline stations that provide hydrogen) is defined by the maximum hydrogen throughput of stations and a minimum coverage factor (minimum number of stations). Below a certain minimum vehicle fraction, the fraction of stations that offer hydrogen will be fixed at the minimum hydrogen coverage (typically 10% of existing gasoline stations). Station size can be varied in the model and in this case, the minimum coverage will be set at 10% of the final number of hydrogen stations. This minimum coverage is intended to provide early adopters with a reasonable level of convenience in refueling stations [16]. Below the 10% threshold, as overall demand increases, the number of stations remains fixed so that the hydrogen demand at each station will grow. After the demand for hydrogen exceeds the quantity of hydrogen that can be supplied by 10% station network, THERM increases the number of stations based upon the hydrogen demand and assumed maximum station size, and the hydrogen demand is divided evenly among the stations.

Pipeline distribution costs and integration into THERM

This model component combines the functional relationship developed for the idealized city between the number of refueling stations and total delivery distance with a pipeline cost model to calculate the delivery costs of hydrogen via compressed hydrogen pipelines. The length of the pipeline is a key factor in determining the associated costs. The pipeline length is specified as a function of the number of refueling stations by the formulas described above. The key assumption is that the marginal increase in pipeline length in adding additional stations is the difference in pipeline length for specific refueling station configurations.

$$\Delta L_{pipeline} = L_{pipeline,N_2 stations} - L_{pipeline,N_1 stations} \qquad [1]$$

This increase in pipeline length will determine the capital and installation costs for pipelines in a given year, while the energy costs are calculated from pipe flow equations. These costs in addition to operations and maintenance costs make up the hydrogen delivery costs. Because of the large initial costs associated with installing distribution systems within a city, it is assumed that the hydrogen distribution systems are sized to handle the maximum flowrates expected. Initially installing larger pipeline diameters to handle larger flowrates does not add significant cost to small pipelines used for distribution[17]. Thus, annual costs are associated with adding incremental pipeline capacity to handle additional stations and the operations, maintenance and energy costs associated with operating the pipelines. For pipelines in the flowrate of interest in this model, the typical capital costs are $150,000/km. The non-capital costs associated with the pipeline are significant and include engineering, right-of-ways, and installation. These values are difficult to determine explicitly and are assumed to be $300,000/km for rural pipelines between the plant and the city gate and $500,000/km for the urban distribution pipelines within the city gate.

2.5 Refueling station models

As stated above, the number of refueling stations is determined by three factors, the hydrogen demand, the minimum station coverage, and the maximum size of a refueling station. The minimum station coverage essentially provides a threshold number of stations regardless of the hydrogen demand. However, once that threshold is exceeded, the number of stations is just the hydrogen demand divided by the maximum refueling station size. The hydrogen demand at the stations determines the capacity of the equipment for refueling, including storage tanks, compressors, and dispensers. Each year that additional stations are needed, the land costs, capital equipment and installation costs are assessed. In addition, operating, maintenance and energy costs are calculated for each station.

On-site natural gas steam reformers

The hydrogen production from natural gas is accomplished via small-scale natural gas steam reformers and has the same components as large centralized plants (i.e. reformer, water gas shift reactors and a pressure swing adsoption unit). Costs and technical data for these systems are based on data from H2Gen Innovations Hydrogen Generation Module (HGM). The turndown ratio of the module is 40% and the thermal efficiency of the natural gas to hydrogen conversion is approximately 73%.

These onsite reformers are the only major components that will need to be replaced when the transition from distributed to centralized production occurs. It is assumed that this equipment was financed and the replacement cost will be the remaining unpaid capital cost (i.e. the fraction of the total capital cost based upon the age of the reformers), a decommissioning/removal cost plus the cost of the new equipment. The unpaid capital cost is equal to the depreciated value assuming straight-line depreciation. This equipment is likely to have value and could be sold in other smaller or less mature markets that have not made the transition to centralized hydrogen production.

H_2 storage, compression and dispensing

These components will be a part of the refueling stations in both the distributed and centralized hydrogen production pathways. In fact, the equipment that has not has not reached the end of its useful life is assumed to be reused (e.g. compressors, storage tanks and dispensers).

The hydrogen delivery pressure depends upon the delivery method. Pipeline delivery pressure may be as high as 1000 psi, while trucks can deliver at 3000 psi though pressure will decrease as the tubes are emptied, and liquid H_2 will need to be vaporized and compressed. Regardless of delivery method, H_2 must be compressed to storage pressure of 6000 psi prior to vehicle feuling. The compression energy is calculated via adiabatic compression assuming a compressor isentropic efficiency of 80%. The compressor cost is based upon cost data from Ogden [18] and SFA Pacific [6].

The storage can be sized in a number of ways. The hydrogen storage needs at a refueling station will depend upon the rate of H_2 production or delivery, the throughput of the compressor, and the rate of dispensing. Pipeline delivery is assumed to reduce the amount of storage necessary as compared to onsite reformers. In either case, the compressor sizing is an important parameter in determining the size of storage systems. In addition, there is assumed to be storage at the central plant equal to 50% of the daily flow. Compressor and storage sizes for the onsite and delivered hydrogen stations are shown in Table 3.

Refueling Station Costs and Model Integration

Costs for refueling stations (with onsite production or pipeline delivered hydrogen shown in Table 3) are assumed to be static over the life of the transition. The cost and maximum size of the stations is fixed regardless of how many stations there are so there is no assumed learning, R&D or manufacturing cost reductions.

Table 3. Cost Assumptions for Hydrogen Refueling Stations

	SMR station	Pipeline Station
SMR Module Cost (HGM-1000)	$450,000	
SMR Module Output	600 kg/day	
Compressor Base Cost ($C_{b,comp}$)	$15,000	
Compressor Base Size ($S_{b,comp}$)	10 kW	
Compressor Scaling factor (α)	0.9	
Compressor Size	100%	150%
Station Storage	150%	50%
Storage Cost	$500/kg	
Natural gas feedstock cost (Station)	$7.00/MMBTU	
Installation, Engineering and Facilities	35% of Installed Capital	
Non-fuel O&M (annual)	10% of Installed Capital	

We model two types of refueling stations, one with onsite reformers, and the other with delivered hydrogen. When the model begins, the default system pathway is onsite hydrogen production at the refueling station. At the transition year, all of the hydrogen that is provided to consumers at the station is produced at a central plant. This switch to centralized production leads to significant costs, including building the central production plant and pipeline networks as well as paying off the remaining capital costs that are owed on the onsite steam reformers. We assume that the remainder of the station equipment (storage, compressors and dispensers) can be reused. The hydrogen demand at each station is passed from the demand module to either of the refueling station modules depending upon which type is used.

2.6 Economics metrics

In order to adequately compare and assess the economic and environmental characteristics of the transition from distributed to central hydrogen production, economic, energetic and environmental metrics are needed. These include levelized cost, optimal transition year, simplified cash flow (including minimum cash flow), breakeven year, energy use and emissions.

Levelized costs

The model aggregates the costs for each system model component on an annual basis in a summary worksheet. This annual cost data are used to calculate the levelized costs by summing all of the capital, land, installation, operation and maintenance, fuel and energy costs over different time horizons and dividing by the total cumulative hydrogen demand in that period. The simulation allows us to model different configurations and pathways to determine the best options for meeting the hydrogen demand for a particular demand profile. Given the long time periods involved, the values of costs incurred in the future are not discounted to present value. The concept of low or zero discount rates to deal with long-term issues especially related to sustainability and intergenerational equity may be somewhat controversial but there is a large literature on this subject. We felt it best to adopt this practice for our levelized cost calculations because they will allow us a more useful and transparent comparison of transitions occurring at different times.

Cash flow and breakeven year

If the hydrogen selling price profile is assumed, the difference between cost and price will permit the calculation of the hydrogen producer cash flow. Because of the low demand and higher hydrogen costs in the early years of the transition coupled with growth in demand over time, the cash flow will likely be negative during the early years and shift positive after a period of time. The set of assumptions that are used in any given simulation run will affect the trajectory of the cashflow and the amount of time it takes for the infrastructure investment to break even.

Optimal Transition year

Different scenarios are considered for any given set of assumptions (called a 'run') where the timing of the transition from distributed to onsite production is varied to investigate the costs and their sensitivity to timing. The transition year is varied in time steps of five years and economic metrics are evaluated for each of the different runs to determine which transition year yields the best infrastructure economics over the specified run. The optimal transition year will occur earlier for fast transitions and later for slower transitions.

3. RESULTS AND DISCUSSION

This section compares both static and transition analyses from the THERM-NG model of distributed and central hydrogen production. The first sub-section describes results of the static analysis which compares the costs related to distributed and centralized production as a function of the scale of demand and the city size. The second sub-section describes the costs associated with the transition from a series of distributed refueling stations with onsite H_2 production to a central H_2 production facility with pipeline distribution. The sensitivity of these costs to several geographic and design parameters is investigated.

3.1 Static analysis

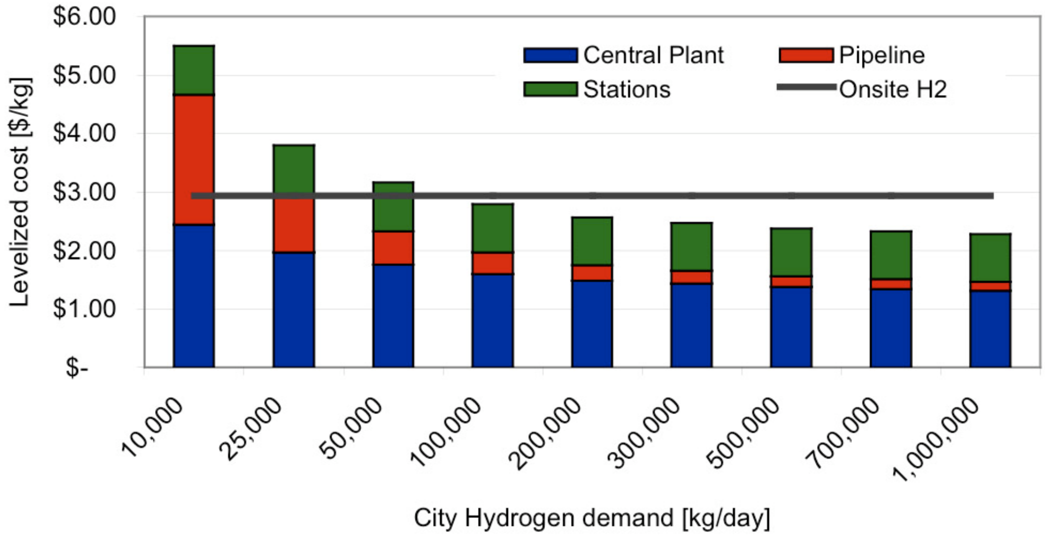

Figure 5 Steady state cost calculations for centralized (bars) and distributed (line) for a range of total hydrogen demand. [Note: x-axis not to scale]

Though THERM is a transitional model, its underlying components can describe centralized and distributed hydrogen production, distribution pipelines and refueling stations operating in a steady state manner (constant demand over the lifetime of the equipment) and calculate costs. Figure 5 shows the levelized cost ($/kg) for central and distributed hydrogen infrastructures. It is assumed in this analysis that the cost of hydrogen from distributed production at a refueling station is the same once the total demand exceeds the size of several refueling stations (>3000 kg/day) and the stations are fully utilized. The cost of hydrogen from a centralized infrastructure (plant, pipelines and refueling stations) changes as a function of its scale. The central plant costs are calculated for different sized cities with 100% market penetration of hydrogen (assuming a population density of 1500 people/km^2). Larger plants and higher hydrogen demand and distribution can be significantly cheaper than smaller systems as industrial equipment (e.g. reformers, compressors) often follows a power law function for capital costs. The cost of onsite production is approximately $3/kg at a wide range of demands, small central infrastructure systems can exceed $4/kg while very large centrally produced hydrogen can cost under $2.50/kg. From this static analysis, it seems clear that below a certain demand level, onsite hydrogen production would be favored while at larger demand levels, centrally produced hydrogen would be favored.

3.2 Transition analysis

The general pattern shown in Figure 6 is that there is an initial period of slight negative cash flow associated with hydrogen production onsite and low hydrogen demand. Onsite production can be thought of as operating in a steady-state mode since the stations are assumed to be fully utilized. Thus, since the steady state hydrogen cost from onsite production (see Figure 5) is greater than the assumed \$2.50/kg selling price, there is a negative cash flow. Figure 6 shows that the different trajectories of the cash flow are a result of the year the transition to central production is imposed onto the system. In the case of the 2015 transition, the switch to a large central plant (500,000 kg/day) with pipelines when demand is fairly low (11,200 kg/day) leads to significant losses until the demand reaches a critical point. As demand increases, the plant and pipeline utilization increase, leading to a decrease in the cost of hydrogen towards its steady state (full utilization) value. As the cost of hydrogen decreases, the cash flow eventually reaches a minimum and becomes less negative.

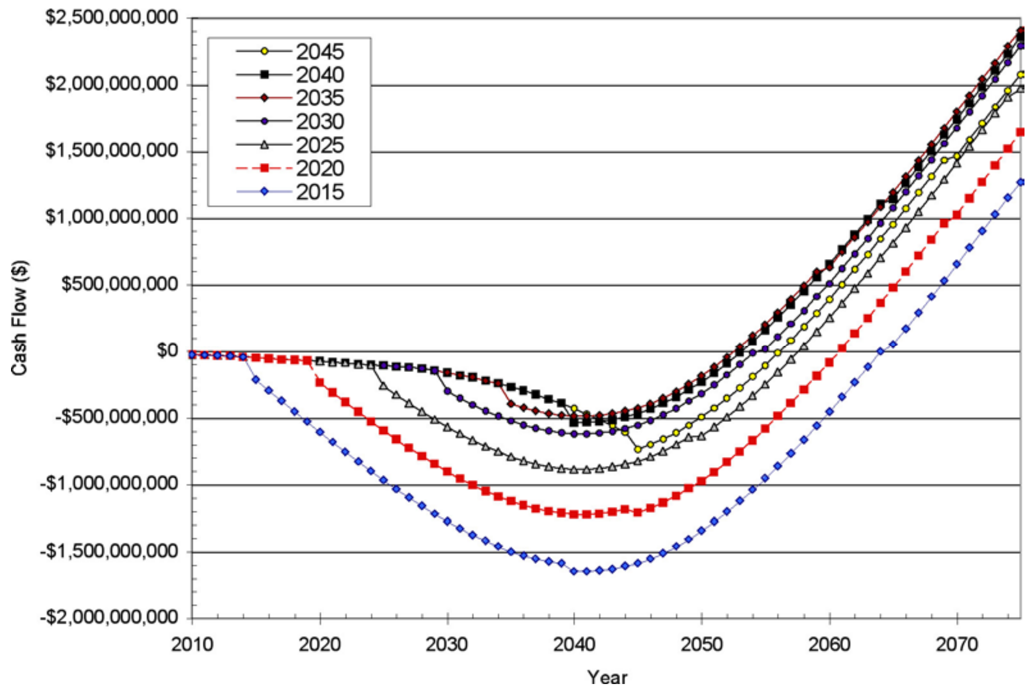

Figure 6 Cash flow profiles for one specified demand profile (medium low growth, logistic) with different specified transition years (2015 to 2045) for a selling price of \$2.50/kg.

The minimum cumulative cash flow and the year at which the cumulative cash flow turns positive (breakeven year) are two important measures of a transition (see Figure 7). Comparing the 2015 transition to later transitions, it is clear that transitioning too early leads to a more negative minimum cash flow and later breakeven year because too much money is lost at very low hydrogen demand when the large scale hydrogen infrastructure is poorly utilized. It is also possible to transition too late (2045 transition) which leads to a more negative minimum cash flow and a later breakeven year than the optimum transition. This optimal transition year is only valid for the demand profile associated with this scenario. A faster ramp up in demand would accelerate the losses associated with onsite H_2 production and decrease the losses associated with the underutilization of the central plant, leading to an earlier optimal transition year.

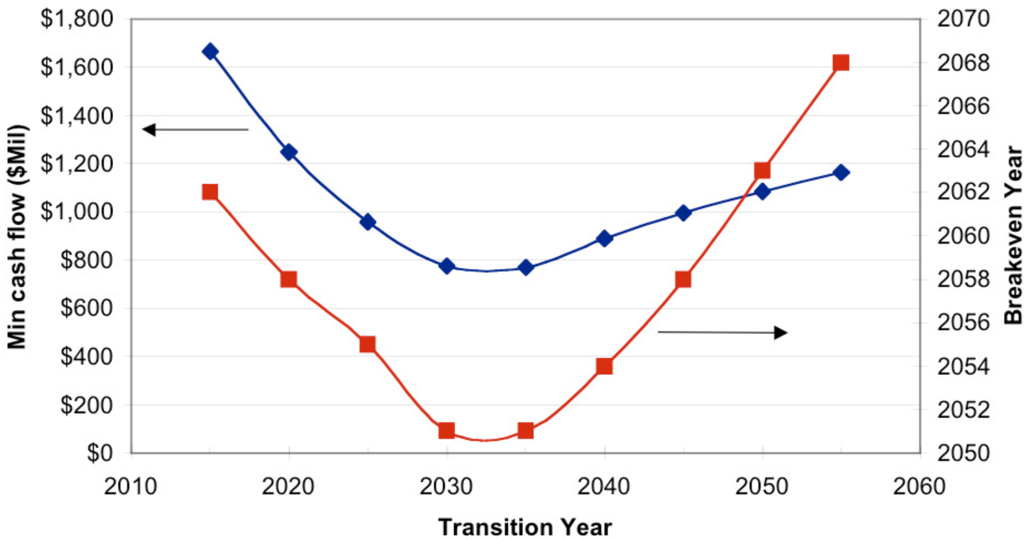

Figure 7 Variation in minimum cash flow and breakeven year as a function of the transition year between distributed and centralized H_2 production for a given demand scenario.

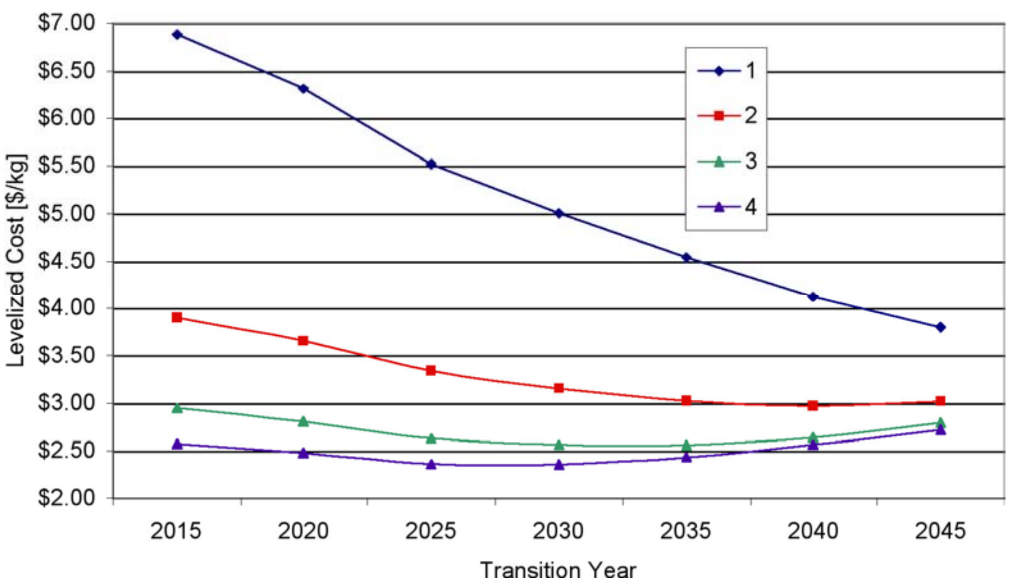

Figure 8 Levelized cost (40 year time horizon) of hydrogen [$/kg] for different growth rates and specified transition years.

The trend in Figure 8 is that faster growth rates tend to lower the levelized cost over the 40 year time horizon, due to less underutilization of the central plants. The curves associated with growth rates 2 through 4 have a minimum levelized cost associated with them (indicated in Table 4). Growth rate 1 doesn't not show a minimum levelized cost because of the use of 2045 as the last transition year. In the figure, the slow growth rate (1) shows a large variation in levelized cost as a function of transition year, while the variation in levelized cost around the optimal transition year is fairly low.

Transition Year	Growth Rate 1	2	3	4
2015	9192	11220	13572	16626
2020	14034	20790	30180	44628
2025	21306	37944	64734	110682
2030	32118	67458	**129312**	**231150**
2035	47904	114780	227940	367998
2040	70362	**182448**	337746	453264
2045	101148	264432	421344	486156
2050	141246	345054	466968	496158
2055	**190086**	408792	487116	498966

Table 4. Daily hydrogen demand [kg/day] at the specified transition year for different growth rates. Highlighted cells are the optimal transition year shown in Figure 8.

The data in Table 4 show that at the optimal transition year, the hydrogen demand is greater than 100,000 kg/day, which approximately corresponds to the steady state demand that yields equivalent levelized costs in Figure 5. These two results are not entirely comparable because Table 4 shows the values for an underutilized plant (whose total capacity is 500 tons/day) while Figure 5 shows costs for fully utilized plants of different sizes.

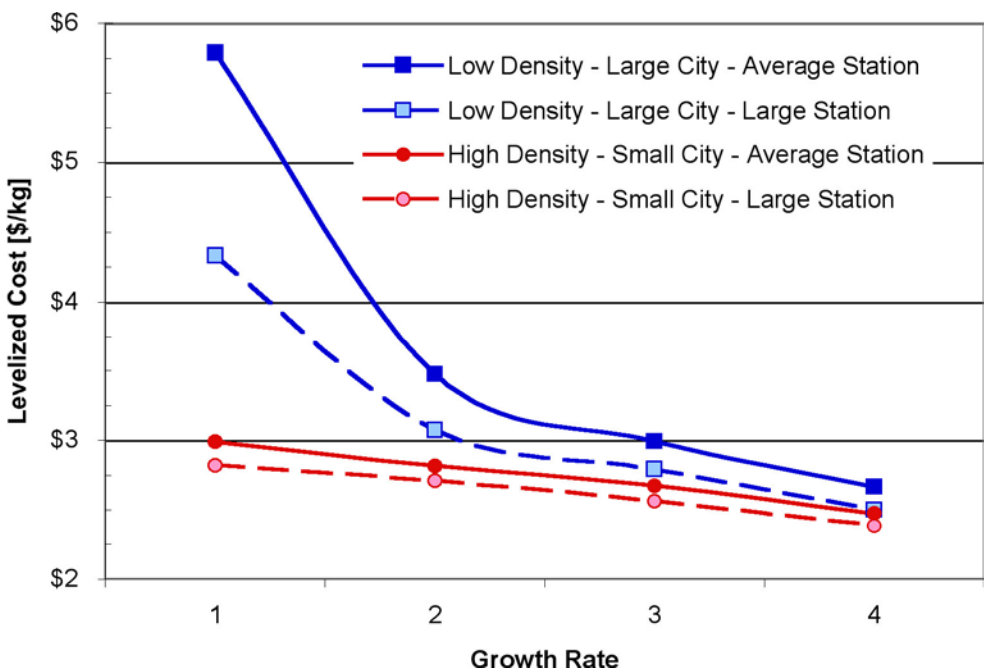

Figure 9 The effect of refueling station size (1500 and 3000 kg/day stations), city size and density and growth rate on levelized hydrogen cost.

The above analysis is made for a city of approximately 1,000,000 people, which has an average population density of 1500 people/km^2. The city size and population density can dramatically affect the cost of centralized infrastructure through changes in central plant size and the length of distribution pipelines (it is assumed that the unit cost of hydrogen from distributed production is independent of these factors). Figure 9 shows the variation in levelized cost (40 year time horizon) for different sized cities and a change in the refueling station size (3000 kg/day vs 1800 kg/day). Increasing refueling station capacity (from 1800 kg/day to 3000 kg/day) will decrease costs by decreasing the number required to meet a given hydrogen demand and reducing the length of the distribution pipeline. Also shown on this graph is a comparison of a low-density large city compared with a high-density small city as a function of the four logistic demand profiles. The low-density, large city (750 people/km^2, population 2 million) has much higher costs than the high-density, small city (3000 people/km^2, population 0.5 million) for the slow demand profiles, due to higher central plant costs that are significantly underutilized and higher distribution costs. With the high growth demand profiles, the levelized cost of hydrogen during the transition for these different scenarios tend to converge.

Figure 10 shows the sensitivity of the levelized cost of hydrogen [$/kg] over a 40 year time horizon to the number of central plants and the demand growth profile. There is a distinct decrease in levelized cost as a function of growth rate. Faster increases in hydrogen demand leads to higher levels of utilization for the central plants, which lowers the production cost of hydrogen. In addition, higher hydrogen production volumes reduces the unit costs of hydrogen distribution pipelines. Another demand parameter that affects the hydrogen levelized cost is the shape of the demand profile. The figure shows that the linear growth rates (solid symbols and unbroken lines) have lower levelized costs than the logistic growth rates (open symbols and dashed lines) at the slower growth rates. At the two faster growth rates (3 and 4) there is significant convergence between these scenarios and the differences in costs between the two types of growth become relatively minor. The final point of interest relates to the sensitivity to the number of central plants. The number of central plants is varied (1, 2 or 3) where the final hydrogen demand is spread evenly among the hydrogen plants (i.e. 500, 250 and 167 tons/day for the base city size). The central H_2 production plants are only built when the demand is sufficient to warrant their installation thereby allowing the deferment of capital expenditure, the building of central production capacity in smaller increments, and an improvement in the utilization of the central plants (average % utilization or capacity factor over the life of the central plant). It is clear from Figure 10 that when there is only one central plant and demand grows relatively slowly, the levelized cost is significantly higher due to the significant underutilization of the production plant. As the growth rate increases or as plants are added in smaller increments, the average capacity factor of the H_2 plant increases thus lowering the capital component of the levelized cost.

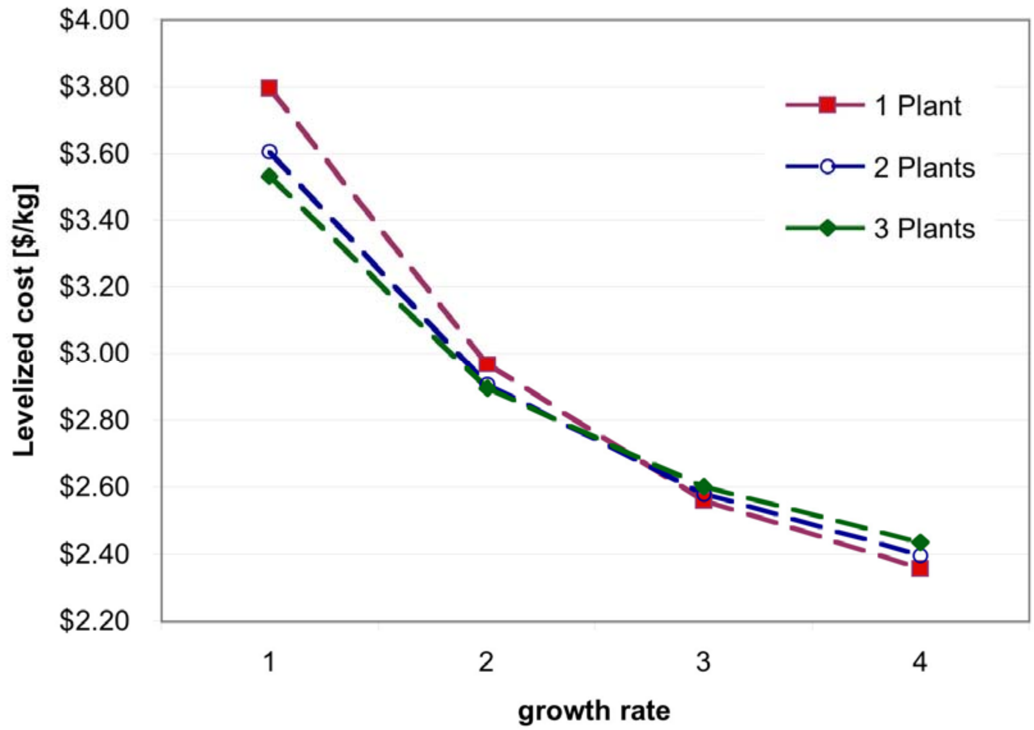

Figure 10 Levelized cost (40 year time horizon) sensitivity to number of central plants, and demand profile parameters.

4. CONCLUSIONS

Transitioning to a hydrogen economy will be expensive as there are many costs associated with building up a widespread, convenient infrastructure that will replace the current gasoline refueling infrastructure. However, the costs of the infrastructure and the resulting cost of hydrogen can be reduced by strategies for building up infrastructure in an intelligent manner. The model described here, the Transitional Hydrogen Economy Replacement Model w/ Natural Gas (THERM-NG) is used to run scenarios with different input conditions and assumptions to understand any economic and environmental benefits or costs associated with these strategies. The effect of optimal strategies appears to be most important for cities with slow demand growth profiles. This is because infrastructure will be invested but may not be fully utilized for long periods of time as growth occurs slowly. When growth is very rapid, variation in the transition year, the size of central plants or refueling stations do not appear to make a significant difference. THERM-NG indicates that no significant lock-out occurs in first building a distributed infrastructure. At a given scale, the centrally produced hydrogen becomes more economical and a transition can occur.

THERM-NG is a useful tool for estimating the cost of hydrogen infrastructure in both static and transitional scenarios because scripting in Microsoft Excel and Visual Basic makes it simple for users to change parameters in an automated fashion. This allows for a wide variety of input assumptions to be tested quickly and comparisons to be made easily between the cost of these alternatives. The component modules include hydrogen production from central plants and refueling stations, a detailed model of pipeline distribution within a city (which has not been adequately modeled to date), and refueling stations. THERM is a simplified framework that allows for infrastructure replacement scenarios to be run. Additional component modules such as central coal-based hydrogen production, hydrogen from renewables can be added to provide additional insight into when transitions may make sense for different regions with different feedstock resources and constraints. The development of strategies for building up hydrogen infrastructure that are guided by the specific geographic and resource conditions is an essential task that will help to determine where and when hydrogen can and should be deployed.

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