Optimizing the Design of Biomass Hydrogen Supply Chains Using Real-World Spatial Distributions: A Case Study Using California Rice Straw

By

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Abstract

The cost of hydrogen from biomass is not well understood due to the trade-offs between economies of scale at the production facility and diseconomies of scale in the feedstock collection and hydrogen delivery. The hydrogen delivery portion of the cost is particularly hard to understand because three modes of delivery exist with very different cost functions. In order to estimate the cost of hydrogen from biomass, it is necessary to develop an understanding of how these three stages of the supply chain will interact in an optimal system.

This paper develops a methodology to optimize full supply chains for producing hydrogen from dispersed biomass resources and delivering it to the drivers of hydrogen vehicles at refueling stations. A profit maximizing model of the supply chain for use with real-world geographic information is formulated in a mixed integer-non-linear program. The model chooses the optimal number, location, and size of conversion facilities along with the fields that supply each facility and which demands are served by which facilities. In the process the optimal mode of hydrogen delivery is chosen. Engineering-economic models of the cost of each part of the supply chain were developed from literature during model development. A case study using rice straw to produce hydrogen in northern California is presented as a demonstration of the method.

The rice straw case study demonstrated that hydrogen from biomass could be competitive with the projected costs of the distributed production of hydrogen by steam methane reformation (SMR). All cases fell below or within the range of projected costs for onsite SMR with current technology. Cases with high demand density (25% and 50% vehicles using hydrogen for fuel) that can take advantage of lower cost hydrogen delivery are competitive with the future technology case of onsite SMR.

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Introduction

Motivation

Hydrogen has received considerable attention in recent years as an alternative fuel. One main attraction of hydrogen is the flexibility to use multiple primary energy sources from coal to nuclear to wind to produce it. This flexibility is intriguing because it allows for the choice of primary energy sources based on the full suite of attributes of the fuel including non-economic reasons. For example, California's Hydrogen Blueprint Plan calls for 20% of hydrogen produced in California for vehicular use to come from renewable sources (Cal/EPA 2005). Similar actions are taking place in other states and countries. This recognizes that a significant portion of hydrogen produced needs to come from renewable sources if hydrogen is to be considered an environmentally friendly fuel. However, recent studies suggest that renewable hydrogen will to have a small price premium compared to hydrogen from traditional fossil sources (such as steam reforming of natural gas) if hydrogen is to become a competitive, environmentally-friendly alternative to gasoline (NAS 2004).

Biomass gasification is one technology that is being studied as a low-cost source of renewable hydrogen. There have been several recent studies to project the cost of producing hydrogen via biomass gasification (Hamelinck *et al.* 2002; Simbeck *et al.* 2002; Lau *et al.* 2003; Spath *et al.* 2003; NAS 2004; Larson *et al.* 2005; Spath *et al.* 2005). The majority of the studies have established that hydrogen from biomass could be produced in the range of one to two dollars per kilogram of hydrogen at the plant gate. This cost is only marginal higher than fossil options, like steam methane reforming of natural gas or coal gasification, and significantly lower than other renewable options like solar or wind-powered electrolysis whose cost run in the $4-10 per kilogram range (NAS 2004).

A major factor for low cost hydrogen from biomass is the economies of scale of the biomass gasification facility. Low costs are attained with facilities larger than 100 tonnes of hydrogen per day. However, large facilities will require feedstock from relatively far away when compared to small facilities, leading to higher feedstock collection costs which are not explicitly accounted for in the current literature.

When considering waste sources of biomass, such as crop residues, the diseconomies of scale for feedstock collection are stronger. Waste resources are inherently more dispersed than energy crops due to lower yields and different objectives of farmers primarily producing energy crops versus farmers selling residues. Still, waste resources of biomass are likely to be the lowest cost source of biomass in many regions (ORNL 2005) and should be seriously considered in evaluating biomass hydrogen.

The plant-gate cost of hydrogen is only part of the story. Approximately half the cost consumers will face at refueling stations will incur during hydrogen delivery. Delivery costs are highly dependent on both the scale of the facility and the distances that must be traversed from the production facility to the refueling station.

Costly gathering of the feedstock and costly delivery of the hydrogen product cause the choice of an optimal conversion facility size to be highly dependent on the spatial distribution and size of both the biomass resource and the hydrogen demand. A good estimate for the cost of biomass-based hydrogen will require the optimization of the full supply chain for the production and delivery of hydrogen to the end user from biomass including the choice of feedstock supply sources, the location and dimension of production facilities, and the design of the hydrogen distribution network.

Problem Definition

The cost of hydrogen from biomass is not well understood due to the trade-offs between economies of scale at the production facility and diseconomies of scale in the feedstock collection and hydrogen delivery. The hydrogen delivery portion of the cost is particularly hard to understand because three modes of delivery exist with very different cost functions. In order to gain insight into the biomass hydrogen supply chain a series of questions need to be answered.

- What are the costs of each component in the supply chain and how do these costs depend on scale and distance?
- How are hydrogen demand and the biomass supply distributed in space?
- And finally, given a demand for hydrogen and distribution of biomass supply what is the least-cost supply chain for producing hydrogen?
    - Where should conversion facilities be located?
    - How large should conversion facilities be?
    - Which biomass supply points should serve each facility?
    - Which hydrogen demands should be served by each facility and by which mode of hydrogen delivery?

Methodology for Solving the Problem

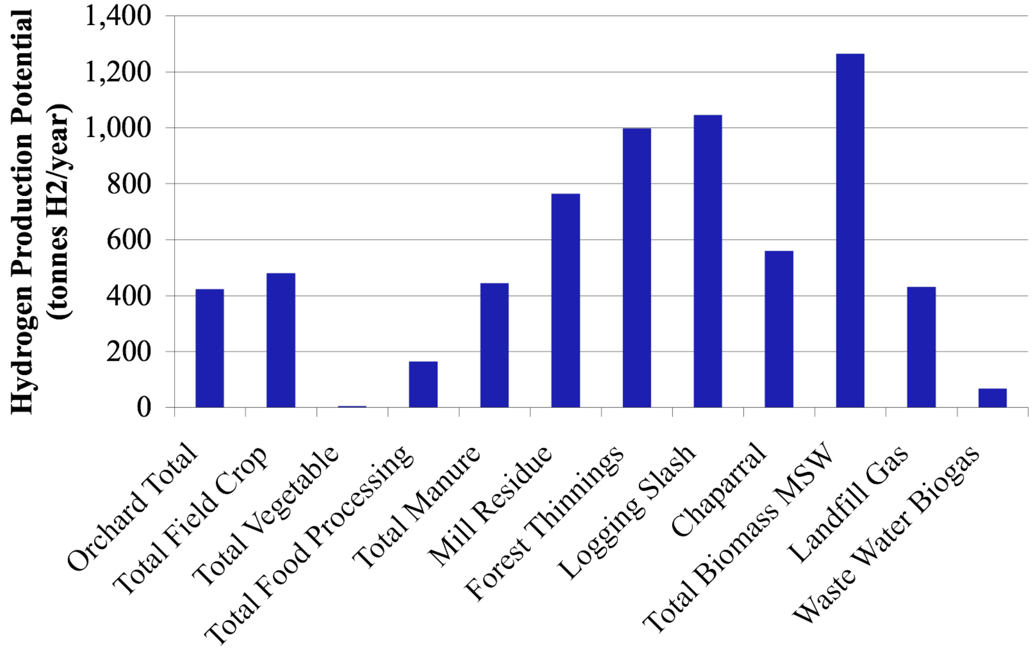
A profit maximizing supply chain model is developed for use with real-world data on the location of biomass supplies and hydrogen demand. This model chooses the optimal number, location, and size of conversion facilities along with the fields that supply each of the facilities and which demands are served by which facilities. In the process the optimal mode of hydrogen delivery is chosen. The model is deterministic and valid for singular configurations of biomass supplies and hydrogen demands. Agricultural wastes are the focus of the model development, but the methodology would need only minor adjustments to analyze forestry and municipal wastes. I present a case study of California rice straw to demonstrate the capabilities of the model.

Why California is a Relevant Case Study

California's policies for air quality and greenhouse gas emissions make it a likely early adopter of hydrogen vehicles. A series of strong hydrogen initiatives already exist in the state including the California Fuel Cell Partnership, a public-private partnership for the development of fuel cell vehicles, and the Hydrogen Highways Network, in which the state is aiding in developing a bare-bones refueling station network that will enable a rollout of hydrogen vehicles in the 2010 - 2015 timeframe.

In California biomass feedstock is most readily available as waste products. A study commissioned by the US Department of Agriculture has shown that California is not suitable for growing the energy crops that have been the focus of research, such as switchgrass, hybrid poplars, and willow (De La Torre Ugarte *et al.* 2003). However, California's large agriculture industry, forest resources, and large urban population all produce waste biomass that could potentially be used for energy and/or refined products (von Bernath *et al.* 2004). If all the waste biomass produced in the state that can be reasonably be collected were converted to hydrogen, over 11 million fuel cell vehicles could be powered by what is currently waste. A summary of the hydrogen potential from the California's waste resources is given in Chart 1.

Chart 1: Hydrogen Production Potential from Waste Biomass in California[1]



The agricultural residues which are the focus of this research are shown the two bars to the far left. Rice straw, the subject of the case study presented later, has the potential to produce 176 tonnes of hydrogen per day; enough to fuel 290,000 fuel cell vehicles. The agricultural residue resource is concentrated in the Central Valley; shown in Figure 1. While this resource does not match population, much of this resource is near large fuel demands along the I-80 corridor from San Francisco to Sacramento.

The methodology developed in this work can be applied to the forest wastes and the municipal solid wastes resources with minor adjustments in cost functions.

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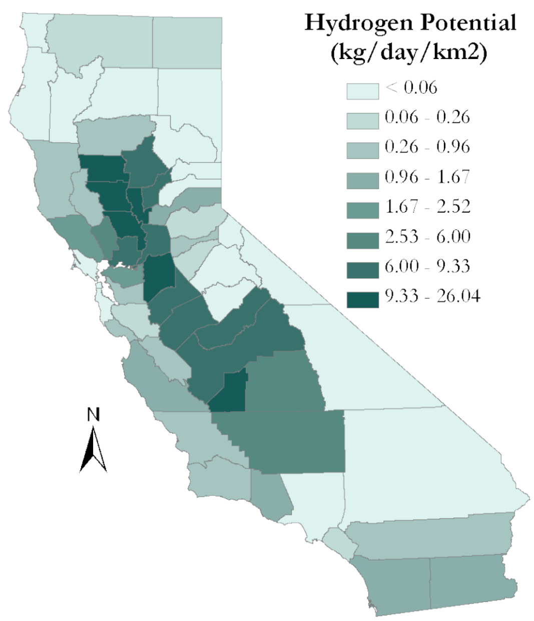
[1] Adapted from von Bernath *et al,* (2004). See Appendix A for an explanation of assumptions.

Figure 1: Map of Hydrogen Potential from Agricultural Residues in California



THESIS STRUCTURE

Chapter 2 provides a literature review of relevant works which include studies on hydrogen gasification, hydrogen delivery, biomass collection, biomass facility siting/sizing, and facility location problems in operations research. Chapter 3 gives a detailed description of the methodology developed for designing optimal waste biomass hydrogen production infrastructure. A case study of using rice straw to meet a portion of the hydrogen demand in northern California is described in Chapter 4. This chapter also gives a detailed description of the cost functions used and how they relate to the system design. Chapter 5 concludes the work with a discussion of the policy implications, lessons learned, and future extensions of the research.

Literature Review

Introduction

No work in the literature exists that performs a full systems analysis for hydrogen from waste sources of biomass. In this literature review, I present the current knowledge on the three major components of agricultural waste based-hydrogen; biomass gasification to hydrogen, hydrogen delivery, and agricultural waste feedstock collection. The works in these three fields demonstrate the challenges presented in the design of a hydrogen supply chain using biomass resources. Next, I describe a sample of methods that have been used to solve biomass facility siting and sizing problems for other products. Finally, relevant literature from the operations research field is presented to validate the choice of methodology. I start with a review of biomass resource assessments to demonstrate the relevance of focusing on agricultural wastes.

Biomass Resource Assessments

It is important to understand what biomass resources exist and which ones promise to be most cost effective to utilize if any industry is expected to use the biomass resource. A recent joint study by the U.S. Departments of Agriculture and Energy set out to find if the United States could support bioenergy and bioproducts industries with one billion tons of biomass feedstock, corresponding to a displacement of about 30% of U.S. petroleum consumption (ORNL 2005). The current consumption of biomass in the U.S. is reported as 190 million dry-tons per year. By exploiting available resources along with moderate gains in crop yields, the study projects that biomass consumption could be increased to 1.3 billion dry-tons per year. 933 million dry-tons of that quantity come from the agricultural sector with residues making up 425 million dry-tons.

For the state of California, the California Energy Commission sponsored an assessment of the biomass resource in California for use in bioenergy and bioproducts industries (von Bernath *et al.* 2004). Data was collected on at the county level for both gross and technically sustainable resources. Gross resources refer to total yearly biomass production within the state. Technically sustainable resources are the fraction of the gross resource that the researchers considered technically feasible to harvest due to physical limitations of harvest equipment, political limitations and some economic factors. Agricultural wastes were determined by crop yields and acreage, using residue factors and harvestable fractions. Forestry wastes include logging wastes, mill residues, and forest thinnings for fire prevention. Municipal wastes are the organic fractions of municipal solid waste estimated from MSW trends for municipalities in each county.

Significant quantities of biomass are available for exploitation in California. From the agricultural sector, there exists 21.6 million dry tons per year of biomass. Only 9.6 million dry tons is technically available because much of the gross resource is in manures.

Table 1: California's Biomass Resource in 2005 (million dry tonnes)

	Gross	**Technical**
Agriculture	21.6	9.6
Forest	26.8	14.3
Municipal	37.6	9.7
Landfill Gas	118 BCF/yr	79 BCF/yr
Waste Water Biogas	16 BCF/yr	11 BCF/yr
Total	***86.0***	***33.6***

The technically available resource of agricultural waste, if converted to hydrogen, could power 3.3 million fuel cell vehicles driving 12,000 miles per year with a fuel economy of 55 miles per kilogram, assuming the biomass has an energy content of 16 GJ per tonne and can be converted to hydrogen at 63% efficiency. This resource assessment demonstrates that agricultural wastes in California are a large enough resource to merit research.

Hydrogen Production from Biomass

Many studies have been conducted to estimate the cost of hydrogen from biomass (Katofsky 1993; Hamelinck *et al.* 2002; Simbeck *et al.* 2002; Lau *et al.* 2003; Spath *et al.* 2003; NAS 2004; Larson *et al.* 2005; Spath *et al.* 2005). The cost estimates have a wide range of values for plant-gate hydrogen from a low of $7.18/GJ ($1.02/kg) report by both Hamelinck *et al* (2002) and Lau *et al* (2003) to a high of $33.94/GJ ($4.82/kg) reported in the National Academies study (2004). There are many reasons for the range of cost estimates including differences in opinion on capital cost estimates, efficiency estimates, facility design, and the level technological learning that is assumed. Outside these fundamental differences, assumptions made about biomass costs and facility size are major factors in determining the cost of producing hydrogen from biomass. This thesis is focused on understanding the trade-off between facility size, feedstock cost and hydrogen delivery cost not on settling the debate over which estimate is correct.

The following is a brief summary of each study. The results of these studies are summarized in Table 2, Table 3, and Chart 3 gives the levelized cost of plant-gate hydrogen for each of the studies under common economic assumptions shown in Table 4. This chart removes the variability from input prices, return on capital, and the yearly operating capacity of the facility by calculating a simple levelized cost based on given capital and operating costs and facility performance. A lot of variability remains. I have also included the cost curve used in the model presented here on the chart.

Katofsky (1993) "The Production of Fluid Fuels from Biomass"

This study analyzed four different gasifiers - BCL, IGT, Shell, and MTCI - for the production of hydrogen and methanol from biomass. ASPEN-PLUS models were used to optimize the performance of 368 MW_{th} production facilities for the four different gasifiers using near term technology. These facilities are dedicated hydrogen production facilities. Thermal efficiencies[2] of between 56.4% and 64.5% were calculated with the IGT gasifier at the low end and the Shell and BCL gasifiers at the high end. The economic analysis found hydrogen could be produced for $11.44/GJ[3] on a higher heating value basis (HHV) using the BCL gasifier which is equal to $1.63/kg. Katofsky found the IGT and Shell gasifiers to be more expensive at the scale studied $14.29/GJ ($2.03/kg) and $14.72/GJ ($2.09/kg) respectively. It was assumed that a woody feedstock was available at a price of $2.62/GJ HHV.

Hamelinck et al (2002) "Future Prospects of Methanol and Hydrogen Production from Biomass"

Hamelinck *et al* builds upon the work of Katofsky by looking at what improvements could be made through more advanced technologies, scale economies and co-production of electricity. The advanced technologies examined were hot gas clean-up, ceramic filters with internal shift reaction, and combined cycle electricity production. Three different configurations of the IGT gasifier and two configurations of the BCL gasifier are evaluated using Aspen+ models. The analysis assumes a woody feedstock available at $2.16/GJ. The least-cost configuration at small scale uses the IGT gasifier with ceramic filters ($10.68/GJ ($1.52/kg) at 80MWth to $8.34/GJ ($1.18/kg) at 400MWth). The two configurations of the

[2] Thermal efficiency is defined as $\eta_{th} = \frac{HHV_{H_2out} + electricity_{out}}{HHV_{biomass\_in} + electricity_{in}}$

[3] Adjusted to year 2005 dollars

BCL gasifier produce the lowest-cost hydrogen at large scale ($7.59/GJ ($1.08/kg) at 1000MWth to $7.18/GJ ($1.02/kg) at 2000MWth). Thermal efficiencies for the systems ranged from 51.6% for a facility producing large amounts of electricity to 65.5% for a facility importing electricity to produce the maximum amount of hydrogen. The analysis found no advantage to being a net exporter of electricity but a low cost of electricity was used for both the imported and exported electricity (~$0.03/kWh). A higher value of electricity would improve the economics of producing excess electricity.

Scale economies vary greatly between the five configurations. The BCL facility with combined cycle electricity improved the cost of hydrogen by $3.83/GJ ($0.54/kg) between the 400MW_{th} and the 2000MW_{th} facilities. The IGT with ceramic filters had the smallest improvement of only $0.64/GJ ($0.09/kg) over the same sizes. For all facilities the scale economies diminish, as the facilities get larger due to some components reaching maximum size and needing to be placed in parallel to get larger.

Simbeck and Chang (2002) "Hydrogen Supply: Cost Estimate for Hydrogen Pathways – Scoping Analysis"

In an analysis of hydrogen supply chain costs, the researchers include an estimate for biomass gasification for a 150,000 kilogram per day facility. Under the assumption that an energy crop is the "only guaranteed source for biomass feedstock," an estimated cost of biomass is given as $59 per bone dry ton or $3.60/GJ delivered to the production facility. Hydrogen plant-gate cost of $16.26 ($2.31/kg) is predicted using a Shell gasifier.

Lau et al (2003) "Techno-Economic Analysis of Hydrogen Production by Gasification of Biomass"

Researchers from the Gas Technology Institute (formerly Institute of Gas Technology) performed an analysis using the IGT gasifier for three different feedstocks (bagasse, switchgrass, and a nutshell mix) and at different scales (~80MW_{th} to ~400MW_{th}). The thermal efficiencies for the three different feedstocks are within 2 percentage points of each (60% to 62%). The differences in capital costs are directly proportional to the heating value of the fuel. The higher the heating value of the input fuel the lower the capital cost for the same size of biomass input on an energy basis.

The economic analysis assumes an "nth of a kind" plant; meaning learning is assumed to have reduced the cost of using near term technologies. Over the range of 400 – 2,000 tonnes of biomass per day, a scaling factor of 0.724 is considered appropriate. The scaling factor is a measure of the strength of the economies of scale present in the facility. Scaling factors are between zero and one for facilities with economies of scale with a lower value denoting a stronger scale economy. A gasifier capable of handling 4,000 tonnes of biomass per day would incur high capital cost, therefore two 2,000 tonnes per day gasifiers should be built instead, giving a scaling factor of one beyond 2,000 tonnes per day (~400MW_{th}). This study found the lowest hydrogen production costs of all the studies at $7.20/GJ ($1.02/kg) at ~400MW_{th} to $11.05/GJ ($1.57/kg) at ~80MW_{th}. One reason for the low hydrogen cost is a significantly lower capital cost compared with the other studies. The reported uncertainty in the capital cost is within 30% of the estimate.

A resource assessment was performed to inform this study. It found that the biomass feedstocks considered could be available for $1.57/GJ to $2.67/GJ with a low of $0.66/GJ for the nutshell mix. For the hydrogen cost estimates, a feedstock cost of $1.62/GJ is assumed.

Spath et al (2003) "Update of Hydrogen from Biomass – Determination of the Delivered Cost of Hydrogen"

Spath *et al* analyzed the production of hydrogen from biomass via three technologies, BCL gasifier, IGT gasifier, and pyrolysis, and at three different sizes. The BCL gasifier produced hydrogen for a lower cost than the IGT gasifier for all sizes. This study had by far the highest capital cost estimates of all the studies. The reason for the high costs is mostly due to differences in the installation factor to convert from equipment costs to facility costs. The systems analyzed are smaller, not taking advantage of the economies of scale. The operating costs are also higher than other studies. The result is levelized costs of hydrogen of $15.42/GJ ($2.19/kg) for a large BCL gasifier system to $22.32/GJ ($3.17/kg) for a small IGT gasifier. The base case feedstock is assumed to be available for $0.89/GJ for the smallest facilities and $2.49/GJ for the larger two facility sizes.

This study does not report design performance such as efficiencies. A Monte Carlo sensitivity analysis was performed varying the costs and operating parameters within reasonable bounds. The analysis shows that the cost of hydrogen is highly uncertain under current knowledge. Typical ranges on the distributions were found to be $13/GJ ($1.85/kg).

National Academies of Science (2004) "The Hydrogen Economy"

As part of a study by the National Research Council, an analysis of two "mid-sized" biomass gasification production facilities was carried out. The current technology design uses the Shell gasifier in a system that has a very low efficiency (38.9%) and small scale (24,000 kg

H_2/day). The low efficiency has two effects that increase the cost well above the other studies. The first is that the low efficiency requires that the facility be much larger than others leading to a high capital cost. The second cost effect is an increase in feedstock cost due to more feedstock being required per unit of hydrogen produced. These effects, the relatively small size of the facility, high feedstock cost ($2.94/GJ) and the more expensive Shell gasifier cause the levelized cost of hydrogen to be significantly higher than any other study $33.94/GJ ($4.82/kg).

For the future technology design, an 'advanced' directly-fired biomass gasifier is assumed. This design improves on the current technology by achieving an efficiency of 61.3%, significantly reducing capital costs and biomass required per unit of hydrogen. Improvements in feedstock yield are also assumed reducing the feedstock cost to $1.97/GJ. The net effect of these improvements is to reduce the levelized cost of hydrogen to $16.20/GJ ($2.30/kg) putting it in line with the estimates by Spath *et al* for an nth-of-a-kind plant design BCL gasifier of similar size.

Spath et al (2005) "Biomass to Hydrogen Production: Detailed Design and Economics Utilizing the Battelle Columbus Laboratory Indirectly-Heated Gasifier"

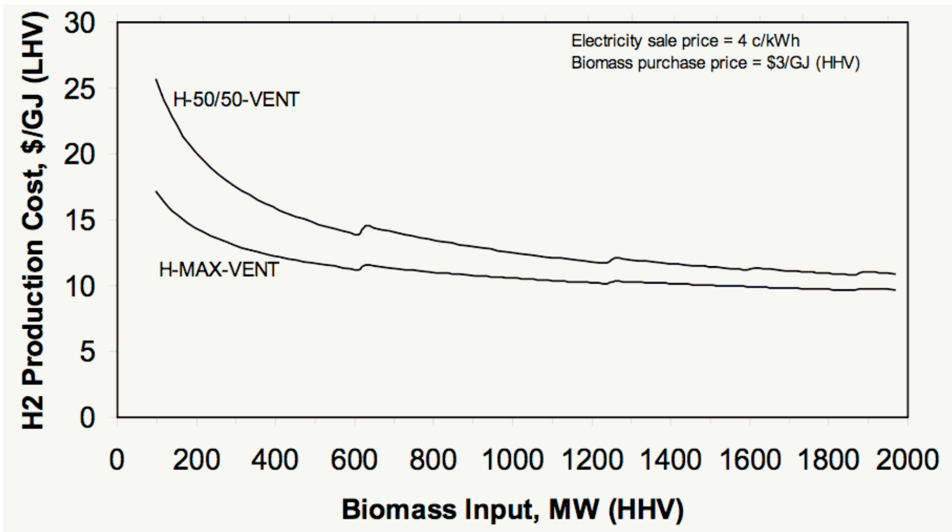
In later analysis, Spath *et al* considered using the BCL gasifier to produce hydrogen and electricity in once through designs at 467 MW_{th}. This analysis included a current technology design and a 'goal' design. The 'goal' design assumes that research and development goals are met in the performance of the tar reformer and therefore demonstrates how improving this one component can affect the system. In both cases all electricity produced is consumed on site with additional grid electricity needed. Significant improvement in hydrogen cost is reported over the 2003 reported costs. The current design reports a levelized cost of hydrogen of \$10.28/GJ (\$1.46/kg) and the goal design improves the cost to \$9.23/GJ (\$1.31/kg). The cost improvements come from all parts. The capital cost is significantly reduced as well as feedstock costs. They assume that hybrid poplars will be available at \$1.58/GJ based on a report by Walsh *et al* (1999) discussed in a following section. The co-production of electricity appears to improve the economics for this study. The opposite finding was reported by Hamelinck *et al.* The conflicting results are partially due to different assumed electricity prices. Hamelinck *et al* assumes \$0.03/kWh while Spath *et al* assumes \$0.05/kWh.

Larson et al (2005) "Gasification-based Fuels and Electricity Production form Biomass, without and with Carbon Capture and Storage"

This study assesses the production of different transportation fuels from biomass including hydrogen. The focus is on larger scale facilities, co-production of electricity, and carbon capture and sequestration. The high efficiencies for production of hydrogen from biomass up to 67.5% were shown by the researchers. The performance and costs are given for four different design of 983 MW_{th}. One design is for maximum hydrogen production with limited electricity production and the other is about half as much hydrogen produced with the rest of the energy going to electricity production. Each design is studied with or without carbon capture and sequestration. The study shows that producing more hydrogen is advantageous for electricity prices up to \$0.04/kWh for \$2.08/GJ feedstock or \$0.06/kWh for \$4.16/GJ feedstock.

Scaling the cost of the facility is done on a component basis. Each component has a maximum size associated with it as well as a scaling factor. Beyond the maximum size of a component, two half-sized components are put in parallel. This gives a decreasing economy of scale as facilities get larger, as seen in Chart 2 below. The feedstock, however, is assumed to available for a constant cost over the entirety of the facility size range.

Chart 2: Economies of Scale in Hydrogen Production[4]



Summary

Katofsky (1993), Spath *et al* (2005), and the National Academies (NAS 2004) studies did not consider facilities at different sizes. Lau *et al* (2003) and Spath *et al* (2003) considered varying facility size up to 125 tonnes of hydrogen per day. Hamelinck *et al* (2002) and Larson *et al* (2005) extended this work by looking at potential facility sizes over 750 tonnes of hydrogen per day. The Hamelinck study assumes a significant improvement in technologies in estimating cost. Therefore the Larson study is used as the basis for the cost functions in the model developed for this work.

Many of these studies develop plausible scenarios of biomass costs (Simbeck *et al.* 2002; Lau *et al.* 2003; NAS 2004; Larson *et al.* 2005) while others took an exogenous biomass price (Katofsky 1993; Hamelinck *et al.* 2002; Spath *et al.* 2005). Only Spath *et al* (2003) varied the

[4] Chart from Larson *et al* (2005) page 69.

biomass feedstock cost with the size of the facility. Not varying the feedstock cost with size leads to assessments that favor larger facilities over small facilities more than assessments that expressly consider feedstock cost.

The other important factors in the engineering-economic models of biomass gasification facilities are the efficiency with which hydrogen is produced and whether or not electricity is co-produced. Co-producing electricity along with hydrogen is improves the economics of producing hydrogen when electricity price is greater than four cents per kilowatt-hour (Hamelinck *et al.* 2002; Larson *et al.* 2005; Spath *et al.* 2005). The optimal mix of outputs will depend on the relative price of hydrogen and electricity. The focus of this work is on hydrogen. Therefore, high hydrogen output conversion facilities are chosen for analysis. The IGT gasifier is reported as having higher efficiencies than the BCL gasifier for high hydrogen output facilities.

Table 2 and Table 3 summarize the economic findings of the gasification studies. Of particular interest is the scaling factors[5] found for the studies that consider scaling. The consensus is for a scaling factor of greater than 0.7. Hamelinck *et al* demonstrate scaling factors increasing toward one as the facility gets very large.

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[5] The scaling factor is the defined as α in the capital cost scaling equation $C_x = C_b \cdot \left({}^{S_x}\!/_{S_b} \right)^{\alpha}$ which estimates the capital cost (C_x) of a facility of any size (S_x) based on a base facility size (S_b) with cost (C_b).

Table 2: Summary of Economic Assumptions and Findings of Gasification Studies

Study - Gasifier	Facility Size (MW_{th})	Hydrogen Capacity (kg H_2/day)	Feedstock	H_2 Eff.	Overall Eff.	Capital Cost (million)	Capital per kg H_2 Cap.	Scaling Factor	Feedstock Cost	Levelized Cost of H_2	IRR
Katofsky 1993											15.1%
- BCL	372	165,000	Wood	72.9%	63.6%	$223.05	$1,352	-	$2.62/GJ	$1.62	CRF
- IGT	368	150,000	Wood	67.0%	56.4%	$274.79	$1,832	-	$2.62/GJ	$2.04	
- MTCI	371	171,000	Wood	75.8%	61.1%	$215.30	$1,260	-	$2.62/GJ	$1.63	
- Shell	368	176,000	Wood	78.6%	64.5%	$385.38	$2,190	-	$2.62/GJ	$2.09	
Hamelinck 2000											10%
- IGT	85.7	31,500	Wood	60.4%	60.3%	$61.54	$1,954	-	$2.16/GJ	$1.52	
- IGT	428.4	157,700	Wood	60.4%	60.3%	$223.02	$1,414	0.8	$2.16/GJ	$1.18	
- IGT	1,701	394,400	Wood	60.4%	60.3%	$472.31	$1,198	0.82	$2.16/GJ	$1.13	
- IGT	2,142	788,500	Wood	60.4%	60.3%	$890.63	$1,130	0.92	$2.16/GJ	$1.09	
- BCL H_2	85.7	36,900	Wood	70.8%	65.5%	$79.36	$2,150	-	$2.16/GJ	$1.64	
- BCL H_2	428.4	184,000	Wood	70.8%	65.5%	$256.93	$1,396	0.73	$2.16/GJ	$1.19	
- BCL H_2	1,701	460,900	Wood	70.8%	65.5%	$491.20	$1,066	0.71	$2.16/GJ	$1.08	
- BCL H_2	2,142	921,800	Wood	70.8%	65.5%	$878.13	$953	0.84	$2.16/GJ	$1.02	
- BCL	85.7	18,000	Wood	34.5%	51.6%	$80.59	$4,477	-	$2.16/GJ	$2.55	
- BCL	428.4	90,000	Wood	34.5%	51.6%	$268.49	$2,983	0.75	$2.16/GJ	$1.67	
- BCL	1,701	227,000	Wood	34.5%	51.6%	$358.27	$1,578	0.31[i]	$2.16/GJ	$1.08	
- BCL	2,142	453,000	Wood	34.5%	51.6%	$665.27	$1,469	0.89	$2.16/GJ	$1.02	
Lau *et al* 2003											15%
- IGT	95.3	37,000	Switchgrass	-	61.9%	$36.50	$986	-	$1.62/GJ	$1.34	
- IGT	190.7	74,000	Switchgrass	-	61.9%	$60.60	$819	0.724	$1.62/GJ	$1.16	
- IGT	381.3	148,000	Switchgrass	-	61.9%	$100.90	$682	0.724	$1.62/GJ	$1.02	
- IGT	82.5	31,200	Bagasse	-	60.0%	$37.00	$1,186	-	$1.62/GJ	$1.57	
- IGT	165	62,500	Bagasse	-	60.0%	$61.10	$978	0.724	$1.62/GJ	$1.34	
- IGT	330	125,000	Bagasse	-	60.0%	$100.90	$807	0.724	$1.62/GJ	$1.18	
- IGT	660	250,000	Bagasse	-	60.0%	$201.80	$807	1	$1.62/GJ	$1.18	
- IGT	100.7	38,600	Nutshell mix	-	61.6%	$36.30	$940	-	$1.62/GJ	$1.27	

Table 3: Summary of Economic Assumptions and Findings of Gasification Studies (cont.)

Study - Gasifier	**Facility Size (MW_{th})**	**Hydrogen Capacity** (kg H_2/day)	**Feedstock**	**H_2 Eff.**	**Overall Eff.**	**Capital Cost** (million)	**Capital per kg H_2 Cap.**	**Scaling Factor**	**Feedstock Cost**	**Levelized Cost of H_2**	**IRR**
Spath *et al* **(2003)**											15%
- BCL	72.7	22,737	Wood	51.4%	NA	$53.80	$2,366	-	$0.89/GJ	$2.62	
- BCL	242.1	75,790	Wood	51.4%	NA	$128.80	$1,699	0.725	$2.49/GJ	$2.36	
- BCL	363.2	113,685	Wood	51.4%	NA	$172.30	$1,516	0.72	$2.49/GJ	$2.19	
- IGT	72	22,737	Wood	52.0%	NA	$72.00	$3,167	-	$0.89/GJ	$3.17	
- IGT	239.6	75,790	Wood	52.0%	NA	$169.40	$2,235	0.71	$2.49/GJ	$2.70	
- IGT	359.5	113,685	Wood	52.0%	NA	$227.20	$1,999	0.72	$2.49/GJ	$2.49	
NAS (2004)											16%
- Shell	95	24,000	Wood	41.5%	38.9%	$125.84	$5,243	-	$2.94/GJ	$4.82	CRF
- 'Advanced'	61.5	24,000	Wood	64.1%	61.3%	$61.36	$2,557	-	$1.97/GJ	$2.30	
Spath *et al* **(2005)**											10%
- BCL current	466.9	140,800	Poplar	49.6%	51.0%	$162.80	$1,156	-	$1.58/GJ	$1.46	
- BCL future	466.9	151,400	Poplar	53.3%	53.3%	$153.10	$1,011	-	$1.58/GJ	$1.31	
Larson *et al* **(2006)**											10%
- IGT ½ H_2	983	172,800	Switchgrass	28.8%	57.5%	$480.50	$2,781	-	$3.12/GJ	$1.53	
- IGT H_2	983	378,720	Switchgrass	63.2%	67.5%	$462.80	$1,222	-	$3.12/GJ	$1.27	
- IGT ½ H_2 CCS	983	179,280	Switchgrass	29.9%	52.2%	$535.60	$2,988	-	$3.12/GJ	$1.96	
- IGT H_2 CCS	983	380,160	Switchgrass	63.4%	64.6%	$491.90	$1,294	-	$3.12/GJ	$1.39	

[i] Potential reporting error.

Chart 3 gives the levelized cost of plant-gate hydrogen for each of the studies under common economic assumptions shown in Table 4. This chart removes the variability from input prices, return on capital, and the yearly operating capacity of the facility by calculating a simple levelized cost based on given capital and operating costs and facility performance. A lot of variability remains. I have also included the cost curve used in the model presented here on the chart.

Chart 3: Levelized Cost of Hydrogen from Various Studies with Common Economic Assumptions

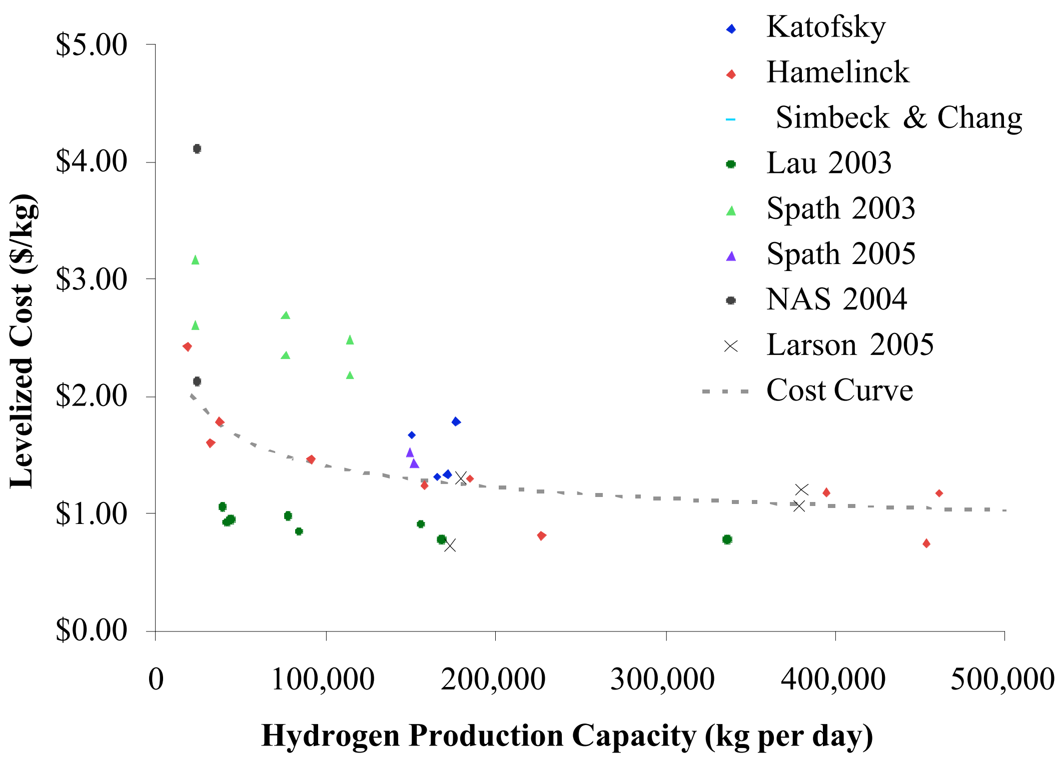


Table 4: Common Economic Assumptions for Chart 2

Feedstock cost	$2.00/GJ (HHV)
Electricity cost	$0.045/kWh
Internal rate of return	10%
Capacity factor	0.9
Lifetime	15 years

HYDROGEN DELIVERY

Studies of hydrogen delivery costs have shown that the cost of hydrogen delivery depends strongly on the hydrogen transport rate, the size of the hydrogen production facility where it originates, and the distances it must travel to get to market (Simbeck *et al.* 2002; NAS 2004; Yang *et al.* 2007). Work done by Simbeck and Chang (2002) and NAS (2004) gave a number of point estimates for delivery costs by the three main modes of compressed gas trucks, cryogenic tanker trucks carrying liquid hydrogen, and hydrogen pipelines. By limiting to a few sizes and distances these studies do not provide a good understanding of the trade-offs involved in choosing a hydrogen delivery mode and whether to site a facility closer to the demand.

Yang and Ogden (2007) provide an analysis of the trade-offs in hydrogen delivery. Hydrogen delivery is split into two cases, transmission and local distribution, in their study. Transmission includes the costs of compression or liquefaction and storage at production facility and transport to a single destination with no dispensing costs. Three modes of hydrogen delivery are analyzed, compressed gas tube trailers, cryogenic tanker trucks, and pipelines. The authors evaluate the costs of transmission for hydrogen transport rates of 2,000 to 100,000 kilograms per day and distances of 25 to 500 kilometers. It is found that compressed gas trucks are least cost for low transport rates and short distances. Cryogenic truck transmission is better at long distances and low transport rates or intermediate distances and transport rates. Pipelines become the least cost transmission mode as the transport rates increase. At short distances pipelines are best at intermediate transport rates while longer distances require higher transport rates to justify the capital cost of the pipeline.

Local distribution costs, the second case of hydrogen transport Yang and Ogden analyzed, include all delivery related costs including compression/liquefaction and storage at plant, delivery, and dispensing/refueling costs. The analysis was performed using four refueling station sizes ranging from 500 kilograms per day to 3,000 kilograms per day for a range of city sizes and hydrogen demands. The compressed gas tube trailers were limited to the 500 kilogram per day stations for practical reasons and they are the lowest cost option for these stations over all city sizes with demands up to 100,000 kilograms per day or more depending on city size. For the larger stations, the pipelines are best for areas with dense demand while the cryogenic tanker trucks are better for larger, less dense cities. The delivery costs range from \$5.77/GJ (\$0.82/kg) to \$13.03/GJ (\$1.85/kg) depending on demand, city size, and refueling station size. This study highlights that the hydrogen delivery costs are very dependent on the configuration of the distribution network and that none of the three modes of delivery is a dominant choice, the choice will change depending on external geographic factors and the level of demand.

An idealized city model is used to discuss local distribution costs. This model uses city characteristics such as city area, population density, and fraction of vehicles using hydrogen to produce a simplified representative network of refueling that would be needed to fulfill the demand in a particular city. The abstraction of intracity delivery cost to simple equations proves to be quite useful in my work in modeling optimal hydrogen infrastructure from biomass.

The Hydrogen Analysis (H2A) project within the Department of Energy's Hydrogen Program is an effort to "standardize transparent analysis for hydrogen technologies and validate the costs" used by the Hydrogen Program to make decisions on research expenditures (DOE 2007). H2A has developed a set of spreadsheet models for most of the important components of hydrogen delivery (DOE 2006). These models detail component sizing for hydrogen stations and terminals as well as providing parameters such as hydrogen losses for the different modes of delivery. The H2A delivery component spreadsheets provide the basis for the hydrogen cost functions used in present model and are described in great detail in the Case Studies chapter.

Biomass Feedstock Cost Studies

A number of studies have looked into the cost of biomass feedstocks. Two reports by Perlack and Turhollow (2003) and Jenkins *et al* (2000) are of particular interest because they provide the detailed engineering-economic costs for the harvest, storage and transport of two agricultural residues, corn stover and rice straw. Summaries of these two reports follow.

Jenkins et al (2000) "Equipment Performances, Costs, and Constraints in the Commercial Harvesting of Rice Straw for Industrial Applications"

Jenkins *et al* used surveys and time-and-motion studies to assess the performance and economics of rice straw harvest, transport, and storage systems. Surveys of growers and custom operators reported the typical costs of each harvesting operation. The custom operators reported lower cost values due to spreading the capital cost of equipment to additional wheat straw harvests at other times of the year. The rice growers surveyed were willing to pay more for rice straw removal than the alternative disposal method of soil incorporation but the surveyed growers were not a representative set of all growers.

In-field time-and-motion studies were performed to estimate the cost and performance of rice straw harvesting systems on an analytical basis. The equipment use times were used to develop engineering-based costs of rice straw harvest. Three baling types were observed with large, square bales having the highest performance in terms of cost and yield per hectare. It was found that total harvest cost range from $7.50 to $42.79 per tonne of rice straw. The large bales had an average total harvest cost of $12.77 per tonne. Transportation costs for the large bales on trucks with a 19 tonne payload were $9.10 per tonne for a 32 km one-way delivery distance. This cost is broken down into loading and unloading cost accounting for $4.58 per tonne and a distance dependent cost of $0.14 per kilometer per tonne. Indirect costs of rice straw harvest are those costs associated with replenishing nutrients removed from the field with the straw. Nutrient replacement cost for potassium, phosphorus, sulfur, zinc and nitrogen are cited to be as high as $17 per tonne of rice straw removed. The largest portion of this cost is the potassium replacement ($9.75 per tonne). The nutrient replacement cost may significantly alter not only the economics of rice straw use but also the life-cycle environmental impact of a fuel produced from the straw by requiring the production of more fertilizers.

Average rice straw yields ranged from 3.1 to 4.5 tonnes per hectare (1.26 - 1.82 tonnes/acre) depending on harvest method. Spring harvest significantly reduced straw yields to 2.5 tonnes per hectare using the better performing large bale harvest method.

Perlack and Turhollow (2003) "Feedstock Cost Analysis of Corn Stover Residues for Further Processing"

Perlack and Turhollow provided an engineering-economic assessment of corn stover harvest and transport for use in 500 to 4,000 tonne per day ethanol facilities. The system assumed was large round bale harvest of stover that has been windrowed by the corn harvester. The bales are transferred to intermediate storage by fast tractors and transport from the storage to the conversion facility is by flat-bed trailer carrying 29 bales. The analysis focuses on the difference in feedstock cost at different sizes of conversion facility. The method employed assumed a fraction of land in a circular area around the conversion facility to be planted in corn yielding available stover. The delivery distances were calculated as straight line distance to from field to facility with a road winding factor. The delivered cost of stover increased from \$44.80 per dry tonne for the 500 tonne per day facility to \$53.70 per tonne for the 4,000 tonne per day facility.

Aggregated Biomass Cost Studies

An attempt at a nationwide state-level analysis was performed by Walsh *et al* (Walsh *et al.* 1999). In order to make an estimate of the quantity of biomass that would be available at three price levels (<\$36.15/dry ton, <\$48.20/dry ton, and <\$60.25/dry ton), simplifying assumptions were made on the delivery distance. For California, the study found that no energy crops would be available at the above prices, and that urban wood wastes followed by forestry wastes and agricultural residues were the state's most plentiful biomass resources. The total in-state resource was found to be 6.2, 8.2 and 11.3 million dry tons per year available for less than \$36.15/dry ton, \$48.20/dry ton, and \$60.25/dry ton respectively. Even at the high range, this is about a third of the technically available resource found in the California Energy Commission report discussed early. This study gives a reasonable first guess at biomass supplies but due to the simplification of delivery distances and state-level aggregation it is of little use for facility sizing.

No papers, to my knowledge, provide a detailed statistical breakdown of potential biomass supplies in a manner that would be meaningful for facility sizing.

BIOMASS FACILITY LOCATION AND SIZING STUDIES

A number of studies have used Geographic Information Systems (GIS) enabled techniques to capture spatially detailed real-world data for use in analysis. Berheim *et al* (1999) demonstrate the use of spatially-detailed rice field and road network data to select the least-cost sites for rice straw storage facilities. Graham *et al* (2000) developed a system to calculate the marginal cost of an energy crop feedstock delivered to multiple optimally-located facilities in a state. First, GIS maps of energy crop production were developed and then shortest paths are found over the road network between every production point allowing for the cost of transport to be calculated. For a given size of biomass facility the marginal cost is calculated for every point on the map through ordering each supply point by delivered cost and summing quantities delivered until the facility size is reached. The delivered cost of the last supply point needed is the marginal cost for that facility. For multiple facilities the point with the lowest marginal cost is selected, the corresponding supply points are removed, and the analysis is run again. Through iteration all supply points become used. This is a good analysis for known facility sizes but not for choosing the facility size.

A question left open by the Graham analysis is whether the marginal cost of feedstock should be used to determine to price of feedstock to the production facility or whether a discriminatory pricing scheme should be used. Zahn *et al* (2005) extend the work of Graham to focus on the difference in feedstock procurement costs under different pricing strategies. The first is a set price for all feedstock that is equal to the marginal cost of feedstock at the size of facility desired. The second is a discriminatory pricing scheme that pays the farm-gate cost plus transportation for all feedstock delivered to the facility. The choice of optimal location of facility is not affected by the pricing strategy but there is considerable variation in the differences in feedstock cost between locations. The feedstock cost for the fixed pricing scheme was between 3 and 16 percent more than the discriminatory pricing scheme for the optimal location depending on size of the facility. This result shows that discriminatory pricing will be advantageous if the additional administrative costs are below 3% of feedstock costs for small facilities and 10% for large facilities.

The papers above focus on locating a facility of known size. Kaylen *et al* (2000) analyze the competition between the economies of scale for a lignocellulosic ethanol facility against the transportation cost of the biomass feedstock using a nonlinear programming model. Costs are divided into four categories, capital costs, operating costs, feedstock cost, and feedstock transportation costs. The capital costs are assumed to have a scaling factor of 0.67, which would be aggressive for a hydrogen facility. Some operating costs also exhibit economies of scale. The transportation costs are linear with distance traveled. The case study is the state of Missouri with spatial information available at the county level. Agricultural wastes (10% availability), logging wastes (33% availability) and energy crops are all considered available for the production facility. Feedstock resources for each county are assumed to be transported from the center of the county in which they occur to the center of the county in which the production facility is located along a grid. A marginal analysis method is used for determining the optimal facility size. In keeping with economic theory, the optimal size is reached when the marginal income from the ethanol and co-products is equal to the marginal cost. Each facility is analyzed separately, making this a single facility model for optimal location. The resulting optimal facility is very large (4,360 tons per day of feedstock) and uses mostly agricultural residues due to lower cost compared with energy crops and lower lignin compared to woody wastes. Of note in the sensitivity analysis, doubling transportation costs ($0.15/ton-mile to $0.30/ton-mile) reduces the optimal facility size to zero, explicitly any increase in feedstock collection distance outpaces the economies of scale of the facility, while doubling the farm-gate cost ($20/ton to $40/ton) only reduces the optimal size by 10%. This analysis gets at the heart of biomass facility sizing but is only useful for single facility siting and sizing.

One paper solves a similar problem as the biomass-based hydrogen problem taking into account supply locations, demand locations and economies of scale. Freppaz *et al* (2004) reports on the development of a decision support system (DSS) to aid regional authorities in making the most of their forest resource for energy, heat and electrical power, production. The DSS uses GIS to gain information on energy demands, forest resource, and the distances in between the two. This data is fed into a mixed integer-linear optimization model that minimizes the cost of energy production. The model chooses the location, size, and fraction of heat versus electrical power of facilities in order to produce a specified fraction of the region's energy requirement. In addition, the model chooses which forest resources should be use to supply those facilities. The results show nearly constant costs up to 16% of the regions energy demand, at which point the cost grows exponentially due to higher cost of acquiring biomass from less accessible areas. The economics of this study favors multiple small facilities producing mostly heat, thus avoiding large capital investments. The use of a mixed integer-linear optimization model allows the researchers to optimize system configurations with multiple possible facilities with variable size and more than one potential type of facility. This method is a suitable match for the biomass hydrogen problem.

One complicating factor in optimizing biomass-based facility sizes was brought up by Jenkins (1997) and should be noted here. He shows that finding the mathematical optimal size with a fixed scaling factor can lead to over sizing the facility if the biomass facility has a scaling factor that asymptotically approaches the value of one. In the example given, an optimal facility size is found for a facility with variable scaling factor. The value of the scaling factor at the optimal size is then used as a fixed scaling factor and a new optimal size is found. The optimal size of the facility with a fixed scaling factor turned out to be 4 times as large as the facility with a variable scaling factor. There was not much difference in the product costs though indicating a very broad optimum in terms of facility size. Variable scaling factors are not used my analysis due to the mathematical complexity that they would cause and this should be considered a limitation of the analysis.

RELEVANT OPERATIONS RESEARCH LITERATURE

The problem of locating and sizing an agricultural waste-based hydrogen conversion facility is a facility location and sizing problem. Many good reviews of facility location models exist in the literature. Klose and Drexl (2005) give a broad overview of the different types of facility location models. Owen and Daskin (1998) focus more on location models that incorporate dynamics and stochastics.

Using the classification scheme presented in Klose and Drexl, the biomass hydrogen supply chain is a capacitated, multi-stage, multi-product location problem with routing for one of the products. The cost of the facility is dependent on the size of the facility making the problem capacitated. There are two stages of deliveries that must be accounted for in feedstock delivery and hydrogen delivery. Three options must be considered for hydrogen delivery; compressed gas trucks, liquid trucks, and pipelines. These can be thought of as three separate products in the supply chain due to their significantly different cost functions. The pipeline delivery mode requires the allocation or "routing" of hydrogen deliveries be explicitly considered because the delivery cost to one demand center will depend on whether deliveries are made to other demand centers. Klose and Drexl state that facility location problems with a discrete set of potential sites can be formulated as mixed integer programming problems.

Most of the literature focuses on an objective of minimizing the cost of a supply chain. Mukundan and Daskin (1991) present an alternative of a profit maximizing model in facility location. The advantage of this system is that the constraint in cost minimization that all demand must be satisfied is relaxed and only demand that is profitable is met. They found that the problem could be formulated and solved as a mixed integer-linear program. A profit maximizing model is appropriate for the biomass-based hydrogen problem due to the fact that it is not likely that all demand would be met with biomass-based hydrogen, and using all available waste biomass supply is also not guaranteed to be optimal.

Modeling the infrastructure of an alternative fuel would be greatly improved by taking into account the temporal dynamics of changing demand and also the great uncertainty faced by the industry. Owens and Daskin (1998) describe a number of approaches that have been taken into adding dynamics in facility location. One approach for single facility location is to solve many static problems and incorporate those solutions as potential sites in dynamic programming model to solve for optimal opening and closing times of facilities. In more complex problems, researchers have been forced to search for near optimal solutions and perform bounding analysis. Stochastic models that are relevant for this problem are models that expressly take in to account the probability distributions in the equations of the model. One of the earliest papers on stochastic facility size by Manne (1961) found that the uncertainty had the effect that would be expected in that more excess capacity is desired. Stochastic models lead to greatly increase the computational time for the model.

The complexity introduced by stochastic and/or dynamic modeling is beyond the scope of the work presented in this thesis. Although I have elected to not include temporal dynamics or uncertainty in this work, it is important to note the limitation that this imposes on the analysis.

In the following chapter, the framework of the mixed integer-non-linear programming model developed to solve the biomass hydrogen supply chain is described in detail. Also described, are the external models that were developed in order to reduce the choice set of the MINLP model that enable the model to solve in a reasonable amount of time.

Generalized Methodology

Introduction

This chapter is meant to introduce the methodology developed to analyze the problem of designing infrastructure for the production of hydrogen from agricultural wastes using real-world, geographically-explicit information. Section 2 explains the profit-maximizing modeling approach used and why it is a good approach to this problem. Section 3 gives a narrative or story about the world that this model operates in and indirectly describes the conditions under which the information derived from the model would be valid. The structural form of the integrated model is introduced in Section 4. Section 5 gives the formulation of the mathematical optimization model developed. Sections 6 and 7 describe GIS-based data preparation steps and the simplification models that are external to the optimization model. Section 8 explains the logistics of cross program communications in the model and the display of the results.

Modeling Approach

The modeling approach taken here is to develop a profit maximizing model for the production of hydrogen from agricultural wastes. In many cases, a profit maximizing model yields the same results as a cost minimization model. However, a profit maximizing model has several characteristics that make it advantageous to cost minimization for this particular application.

The first advantage of profit maximization is the flexibility of constraints it allows. In cost minimization, some constraints must be predetermined that are not necessary for profit maximization. For example one must minimize cost subject to the full utilization of the resource or satisfying a predetermined demand. These constraints are necessary to prevent the model from producing a zero answer. The constraints have the disadvantage of reducing the model's flexibility. In choosing the optimal design, fractional levels of resource use and demand satisfaction may be the best option. A profit maximizing approach avoids these issues by allowing the model to choose which resources to use and which demands to serve based on balancing the costs of production of a good with the price of the good.

The second advantage is in the interpretation of the results. A profit maximizing approach allows for a direct production of a supply curve for waste biomass based hydrogen. This economics-based formulation seeks to resolve the question about how hydrogen can be produced from a resource while recognizing the importance of hydrogen price for answering the question.

The last advantage of the profit maximizing method is that it allows for infrastructure design to respond to price differentials between demand centers. This feature is particularly interesting for modeling a hydrogen production infrastructure competing with onsite steam methane reformation which is highly dependent on natural gas price. It could also represent local policy action regulating the fossil fraction of their fuel supply.

VISION OF THE WORLD EMBODIED IN THE MODEL

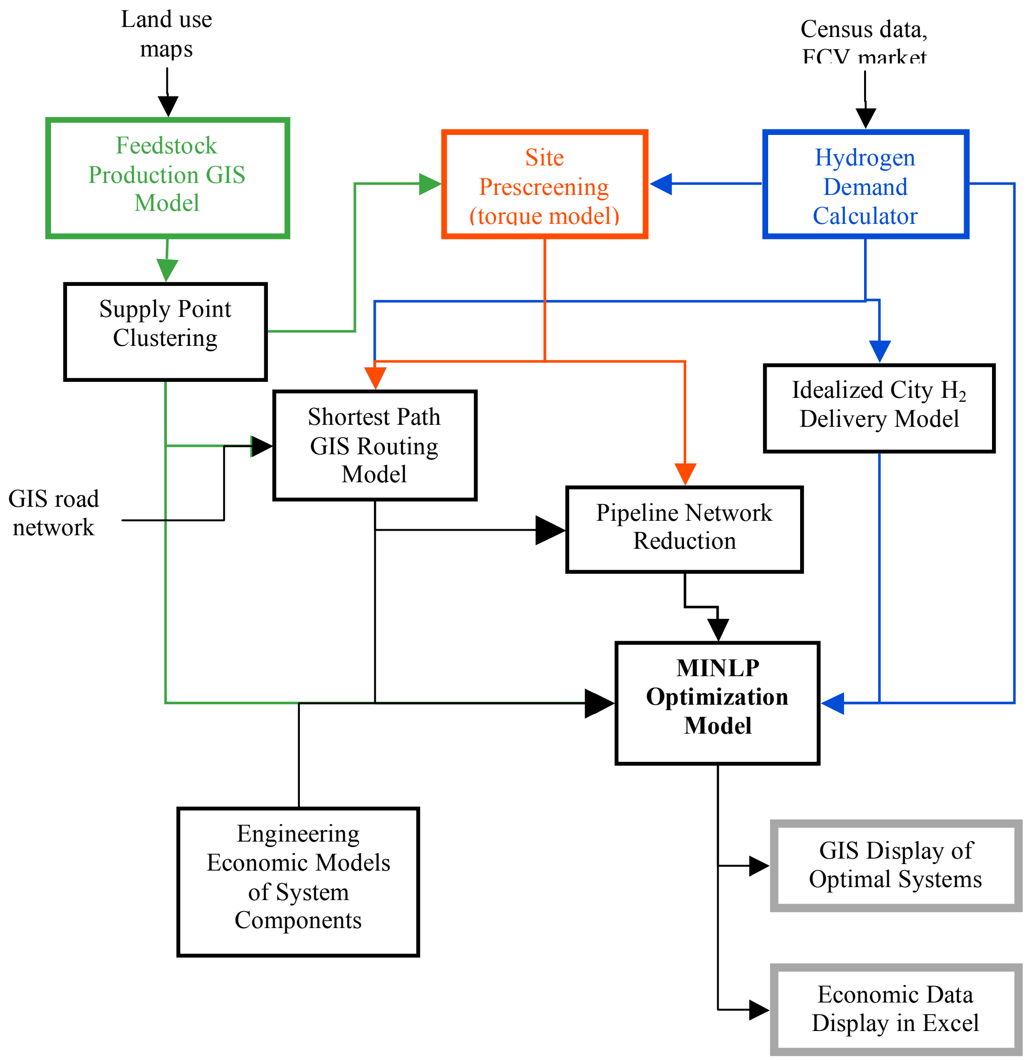
This model describes the optimal behavior of an industry to supply vehicular hydrogen from agricultural residues in a steady-state system of hydrogen demand, selling price, and feedstock supply. If hydrogen from agricultural residues can be delivered to the refueling stations for less than the given selling price then it is profitable for the industry to supply that hydrogen and the infrastructure is built to reap that profit. If hydrogen from agricultural residues cannot be delivered for less than the selling price then the hydrogen is supplied by some backstop technology, such as onsite steam methane reformers that is consistent with the given selling price. In addition, when demand for hydrogen exceeds the supply of feedstock, the difference is made up with hydrogen from the backstop technology.

The decisions that would be made by the industry in the model are the following. What are the best places to build hydrogen production facilities? How large should the facilities be? Where does each facility get its feedstock from? What demand centers are served by each production facility? Which mode of hydrogen delivery is used for each demand center served?

Integrated Model Description w/model flow chart

This work uses real-world data from GIS databases along with an optimization model to find the optimal design of a hydrogen industry based on an agricultural waste. The Geographically Explicit Optimization of Hydrogen from Agricultural Wastes (GEOHAW) model is built on a Mixed Integer Non-Linear Programming (MINLP) model that solves the optimization problem along with GIS data preparation. The MINLP model is limited in the size of the problem that it can solve so outside models are used to limit the choice set to a reasonable size without losing important information for the problem. External models are used to reduce the number of supply points through clustering, choose routes of deliveries, reduce the intracity delivery of hydrogen to a simple equation, and reduce the intercity pipeline network link choice set. In addition, researcher knowledge of the system aided by external models is needed to preselect 'good' facility sites to be considered. Figure 2 shows how the model is integrated in a flow chart.

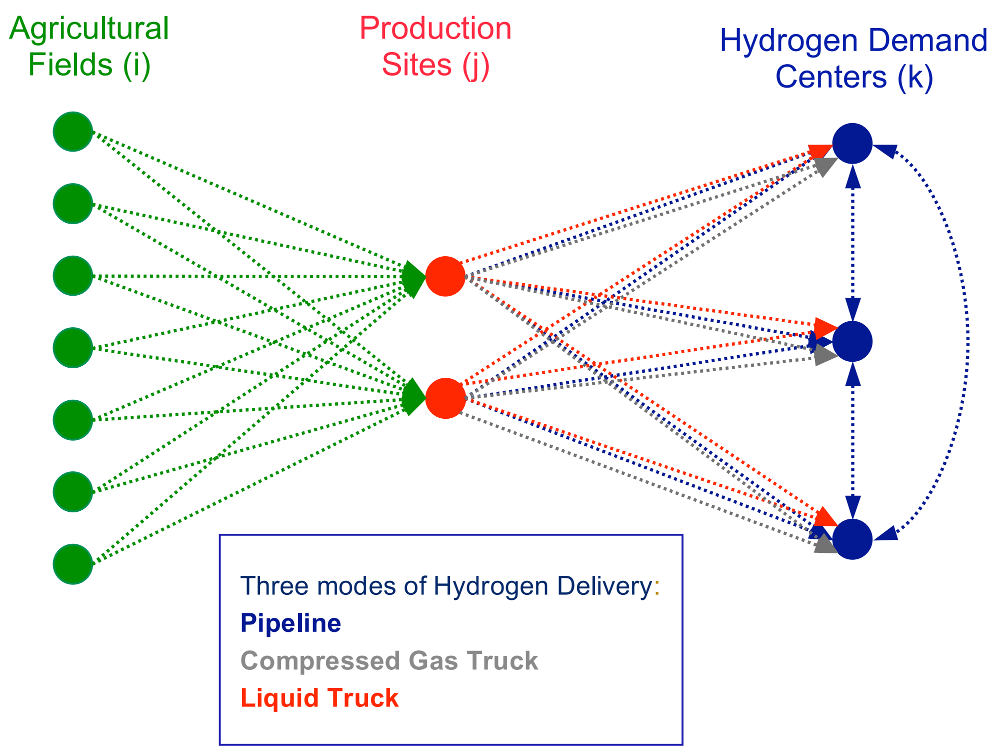
Figure 2: Integrated Model Flow Chart



FORMULATION OF OPTIMIZATION MODEL

An abstract diagram of the agricultural residue-based hydrogen supply chain is provided in
Figure 3Figure 3. The model must define the supplies at each field, the demand at each demand center, and the links from the fields through the production sites to the demand centers.

Figure 3: Diagram of Agricultural Waste to Hydrogen System



Model Notation

subscript 'i' refers to different fields

subscript 'j' refers to different potential conversion sites

subscript 'k' refers to different hydrogen demand clusters

subscript 'm' refers to different modes of hydrogen delivery

Inputs :

$\text{feedstock\_yield}_i \equiv$ feedstock available at field 'i' (tonnes per year)

$\text{P}_k \equiv$ selling price of at demand cluster 'k' ($/kg)

$\text{daily\_demand}_k \equiv$ demand at cluster 'k' (kg/day)

$\alpha_q \equiv$ scaling factor for various technologies

$f2H \equiv$ hydrogen per tonne of rice straw (kg/tonne)

$f\_loss \equiv$ loss factor accounting for feedstock losses in storage and transport

$t\_loss^m \equiv$ loss factor accounting for hydrogen losses at a terminal of mode 'm'

$d\_loss^m \equiv$ loss factor for hydrogen losses in the distribution system of mode 'm'

$\text{d}_{ij} \equiv$ distance between field 'i' and site 'j' (km)

$\text{d}_{jk} \equiv$ distance between site 'j' and demand cluster 'k' (km)

Decision Variables :

$F_{ij} \equiv$ yearly quantity of feedstock delivered from supply node 'i' to conversion site 'j' (Mg/yr)

$C_j \equiv$ capacity of conversion facility at site 'j' (kg H_2 per day)

$T_j^m \equiv$ capacity of hydrogen terminal of mode 'm' at site 'j' (kg H_2 per day)

$H_{jk}^m \equiv$ capacity of hydrogen delivery link by mode 'm' from site 'j' to demand cluster 'k' (kg H_2 per day)

$Hb_{jk} \equiv$ binary variable for the existence of pipeline link between site 'j' and cluster 'k'

$I_{k_1k_2} \equiv$ capacity of pipeline link between demand clusters 'k1' and 'k2' (kg H_2 per day)

$Ib_{k_1k_2} \equiv$ binary variable for the existence of pipeline link between cluster 'k1' and cluster 'k2'

$S_k^m \equiv$ hydrogen supply capacity for demand cluster 'k' by mode 'm' (kg H_2 per day)

Intermediate Variables :

$FC_{ij} \equiv$ cost of feedstock delivered from field 'i' to site 'j' ($/year)

$CC_j \equiv$ conversion cost at site 'j' ($/year)

$TC_j^m \equiv$ terminal cost at site 'j' for hydrogen delivery mode 'm' ($/year)

$DC_{jk}^m \equiv$ delivery costs from site 'j' to cluster 'k' by mode 'm' ($/year)

$IC_{k_1k_2} \equiv$ intercity pipeline delivery costs between cluster 'k1' and 'k2' ($/year)

$LC_k^m \equiv$ local delivery cost within cluster 'k' by mode 'm' ($/year)

$RC_k^m \equiv$ refueling station costs for cluster 'k' for stations receiving hydrogen by mode 'm' ($/year)

$X_k \equiv$ yearly quantity of hydrogen sold at demand cluster 'k' (kg/year)

The Equations

The optimization model consists of an objective function and a set of constraints. The objective function defines the variable of interest and the desired value for the variable. In this case the variable is profit and the desired value is as large as possible. The constraints define the reality of the system in question. They ensure that the abstract math taking place in the model corresponds to some reality. The following is formulation used in the GEOHAW optimization model with explanations as to the meaning of each equation.

The Objective

The objective is to build an industry that will maximize profit with given demands, supplies, and prices. The objective function is the profit function of annual revenue, price multiplied by annual quantity of hydrogen sold, minus annualized cost of production.

Equation 1

$$\text{Maximize } \pi = \sum_{k} \mathrm{P_k} \cdot X_k - annualized\_\cos t$$

$$annualized\_\cos t = \sum_{i,j} FC_{ij}\left(F_{ij}, d_{ij}\right) + \sum_{j} CC_j\left(C_j\right) + \sum_{m,j} TC_j^m\left(T_j^m\right) + \sum_{j,k,m} DC_{jk}^m\left(H_{jk}^m, d_{jk}\right)$$

$$+ \sum_{k_1,k_2} IC_{k_1k_2}\left(I_{k_1k_2}, d_{k_1k_2}\right) + \sum_{m,k} LC_k^m\left(S_k^m\right) + \sum_{k} RC_k^m\left(S_k^m\right)$$

The annualized cost of production will depend on the capacities of the infrastructure built (C_j, T^m_j, S_k^m, H_{jk}^m, and I_{kk}) as well as quantities delivered/produced/converted at each node and along each link. In the formulation of this model the quantities delivered/produced/converted on each link or at each node are assumed to be a constant fraction of the installed capacity this fraction is denoted by the capacity factor.

The cost functions are where the need for non-linear and binary variables arose in this problem. Binary variables are integer variables that take on only the values one or zero. They are not continuous, which makes them computationally difficult. The following equations give the general form of cost functions for the different components of the supply chain. Attention should be paid to where the model is forced to use non-linear and binary variables in order to accurately replicate the cost functions. The detailed cost functions are described in the Case Studies chapter. The equations shown here give a general description of the problem.

The feedstock cost has fixed costs of harvest, storage, and truck loading/unloading per tonne of feedstock and a variable cost that is linearly dependent on the delivery distance.

Equation 2

$$FC_{ij}(F_{ij}, d_{ij}) = (harvest\_\cos t_i + storage\_\cos t_i + delivery\_\cos t_{ij}(d_{ij})) \cdot F_{ij}$$

The conversion cost (CC_j) represents the capital and operating costs of the conversion facility. The capital cost is a nonlinear function dependent on the capacity. The yearly charge paid on the capital is the capital recovery factor (CRF in the equation) multiplied by the total installed cost of capital. Fixed operating costs can be simplified as a multiplier of the capital costs (O&M in the equation). The rest of the operating costs are linear functions of the quantity produced which equals the capacity multiplied by the capacity factor (CF).

Equation 3

$$CC_j(C_j) = (CRF + O\&M) \cdot cap\_\cos t \cdot C_j^{\alpha} + \sum_q \mathrm{var}iable\_\cos t_q \cdot C_j \cdot CF$$

A second cost is added to the supply chain at the conversion facility. The cost of preparing the product hydrogen for transport to the refueling stations is the terminal cost (TC^m_j). The terminal cost has components that are nonlinear in capacity representing the capital and fixed operating cost for the terminal equipment. There are also linear components for the variable cost such as electricity. Each facility has three possible types of terminals and can even have two different types at the same facility.

Equation 4

$$TC_j^m\left(T_j^m\right)=\sum_q (CRF_q + O\&M_q)\cdot cap\_cost_q \cdot (T_j^m)^{\alpha_q} + \sum_q variable\_cost_q \cdot T_j^m \cdot CF$$

The delivery costs must be broken into pipeline and truck delivery cost as the two have different forms to their cost equations. The two truck modes follow a linear function of capital and operating cost associated with the truck cab, trailer, and driver salary. There are also per mile costs associated with fuel, maintenance, and insurance. Truck transmission costs have the form shown in Equation 5.

Equation 5

$$\begin{aligned}
&DC_{jk}^{m=gas,liq}\left(H_{jk}^m, d_{jk}\right)= \\
&(CRF_{cab} + O\&M_{cab})\cdot cap_cost_{cab}\cdot(\#cabs\left(H_{jk}^m\right) + driver_salary(\#cabs\left(H_{jk}^m\right) + \\
&(CRF_{tr} + O\&M_{tr})\cdot cap_cost_{tr}^m \cdot (\#trailers) + per_mile^m \cdot H_{jk}^m \cdot d_{jk}
\end{aligned}$$

The pipeline costs are only capital and fixed operating and maintenance cost because compression is included in the terminal cost. For the size pipes considered in most hydrogen scenarios there is no significant difference between pipe sizes in the per mile installed cost (Parker 2004). For this reason the pipeline costs are treated with binary variables of whether a pipeline is on a link or not. Intercity and intracity pipelines are differentiated in costs with the intracity pipelines costing 1.5 times more than the intercity pipelines.

Equation 6

$$DC_{jk}^{m=pipe}\left(Hb_{jk}, d_{jk}\right) = (CRF + O\&M)\cdot cap\_\cos t\cdot Hb_{jk}\cdot d_{jk}$$

For pipelines there are also deliveries taking place between cities. These intercity deliveries are represented by the following.

Equation 7

$$IC_{k_1k_2}\left(Ib_{k_1k_2}, d_{k_1k_2}\right) = (CRF + O\&M)\cdot cap\_\cos t\cdot Ib_{k_1k_2}\cdot d_{k_1k_2}$$

The local delivery costs follow the same form as transmission costs except that the distances are determined by the idealized city model.

Refueling station costs are different for each mode. The capital costs and fixed operations and maintenance are nonlinear functions of the capacity and linear variable costs also exist.

Equation 8

$$RC_k^m\left(S_k^m\right) = \sum_q (CRF_q + O\&M_q)\cdot cap\_\cos t_q\cdot (S_k^m)^{\alpha_q} + \sum_q \mathrm{var}iable\_\cos t_q\cdot S_k^m\cdot CF$$

The Constraints

In order to model reality, constraints need to be imposed on the objective function. Without constraints, the model would sell infinite amounts of hydrogen while building negative capacity leading to an infinite amount of profit. The constraints can be placed into three categories; capacity constraints, flow constraints, and non-negativity constraints. The capacity constraints restrict quantities to be less than the maximum allowed by the built or given capacities. Flow constraints require that at each node the quantities going in must equal the quantities going out plus or minus the quantities supplied or consumed at the node. Non-negativity constraints require that all physical quantities be positive as they cannot be negative.

Capacity Constraints

The feedstock extracted from a field must be less than the feedstock yield of that field.

Equation 9

$$\sum_j F_{ij} \leq feedstock\_yield_i$$

The yearly capacity of a conversion facility (C_j) must be greater than the hydrogen production potential of the feedstock coming into the conversion facility (F_{ij}). The f2H multiplier converts feedstock quantity into equivalent hydrogen production capacity. The f_loss multiplier accounts for feedstock loss in storage and transport.

Equation 10

$$\sum_i f\_loss \cdot F_{ij} \cdot f2H \leq 365 \cdot CF \cdot C_j$$

The capacity of the terminals (T_j^m) at a conversion facility needs to equal the capacity of the conversion facility (C_j).

Equation 11

$$\sum_m T_j^m = C_j$$

The capacity of the terminal of a mode at a conversion facility (T_j^m) must be greater than the hydrogen leaving the conversion facility by that mode (H_{jk}^m).

Equation 12

$$\sum_k H_{jk}^m \leq t\_loss^m \cdot T_j^m$$

The capacity of the gas truck or liquid truck local distribution and refueling infrastructure ($S_k^{gas,liquid}$) must be at least as large as the quantity of hydrogen coming into a demand cluster by gas truck or liquid truck.

Equation 13

$$\sum_j d\_loss^{gas,liquid} \cdot H_{jk}^{gas,\ liquid} \leq S_k^{gas,\ liquid}$$

The capacity of the local pipeline distribution and refueling infrastructure (S_k^{pipe}) must be greater than the net hydrogen coming into the demand cluster.

Equation 14

$$\sum_j d\_loss^{pipe} \cdot H_{jk}^{pipe} + \sum_{k_2} I_{k_2 k} - \sum_{k_2} I_{k\ k_2} \leq S_k^{pipe}$$

The capacity of the local distribution and refueling infrastructure at a demand cluster must be greater than the amount of hydrogen sold at the demand cluster (X_k).

Equation 15

$$X_k \leq \sum_m 365 \cdot CF \cdot S_k^m$$

The amount of hydrogen sold at a demand cluster cannot be more than the hydrogen demanded at that cluster.

Equation 16

$$X_k \leq daily\_demand_k \cdot 365$$

Flow Constraints

The hydrogen that can be produced from the feedstock going into the conversion facility must equal the hydrogen coming out of the conversion facility. The Hb variable is a binary variable that is one if a pipeline exists and zero otherwise. This variable allows the pipeline costs to be a constant if a pipeline is built and zero otherwise.

Equation 17

$$\sum_i f\_loss \cdot F_{ij} \cdot f2H = \sum_k H_{jk}^{gas} / t\_loss^{gas} + \sum_k H_{jk}^{liquid} / t\_loss^{liquid} + \sum_k Hb_{jk} \cdot H_{jk}^{pipe} / t\_loss^{pipe}$$

The net hydrogen coming into a demand cluster must be consumed. Ib is a binary variable for the existence of a pipeline on link 'k_1k_2'.

Equation 18

$$\sum_j d\_loss^{gas} \cdot H_{jk}^{gas} + \sum_j d\_loss^{liquid} \cdot H_{jk}^{liquid} + \sum_j d\_loss^{pipe} \cdot Hb_{jk} \cdot H_{jk}^{pipe} + \sum_{k_2} Ib_{k_2k} \cdot I_{k_2k} - \sum_{k_2} Ib_{kk_2} \cdot I_{kk_2} = X_k$$

Non-negativity constraints

All capacities and delivered quantities must have zero or positive values.

Equation 19

$$X_k, F_{ij}, C_j, T_j^m, H_{jk}^m, I_{k_1k_2}, S_k^m \geq 0$$

Combining the constraints and the objective function gives a mixed-integer, non-linear program that requires a global solving algorithm. Due to non-convexity of the problem local optimality will not guarantee global optimality. Global solving algorithms are computational expensive as more of the solution space must be searched to ensure an optimal solution compared with local algorithms. What this means practically is that it is beneficial to provide the MINLP as small a problem as feasible while retaining the solution space that will contain the optimal solution. The following sections explain the methods used for data production from real world information as well as how that data was processed in order to reduce the problem to a manageable size for the MINLP.

GIS-BASED DATA PREPARATION

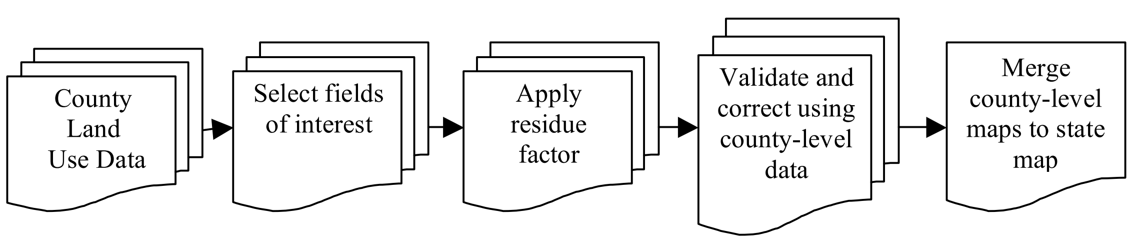
Hydrogen Demand Calculator

Geographically explicit hydrogen demand scenarios are needed in order to predict and optimize the delivered cost of hydrogen. For the work presented here four hydrogen demand scenarios were developed for me by Nils Johnson (Johnson 2006) using a GIS-based hydrogen demand calculator (Ni *et al.* 2005). The demand calculator relies on census data, a target market penetration of fuel cell vehicles and a set of thresholds that filter out areas where the demand is too sparse or the accumulated demand in a cluster is too small to support a refueling station. The hydrogen demand is calculated for each census tract based on the population, a multiplier of 0.7 for the number of vehicles per person, another multiplier for the fraction of vehicles that use hydrogen fuel, and finally a multiplier signifying the fuel economy of the hydrogen vehicles. In this cases presented here, four scenarios, 1%, 10%, 25%, and 50% of vehicles using hydrogen as a fuel, are developed. A filter is applied to rule out census tracts where the demand density is small. The remaining tracts are merged with the neighboring tracts that met the density requirements. The merged clusters are subjected to a filter to see if the cluster could support a refueling station of a specified minimal size.

Feedstock Production Maps

Field-level GIS data describing the location and area of fields is necessary for using this model with real-world data. In the case of California, The Department of Water Resources (DWR 2003) provides land use data sets for each county marking agricultural fields for the study year. To produce an agricultural waste resource map from the land use data sets, I selected those fields corresponding to a specific crop. I then used crop residue yield factors found in von Bernath *et al* (2004) to derive the resource for each field based on its area. After summing the field resources for each county, I compared my county level estimates with those found in the resource assessment performed for the California Energy Commission (von Bernath *et al.* 2004). I introduced county specific correction factors in order to match the estimates of the CEC report. I applied these county correction factors to the field resource estimates. Finally, the county data sets are merged into one state data set. All operations were conducted using ArcView 3.1 GIS software.

Figure 4: Flow Chart of GIS Operations for Feedstock Maps



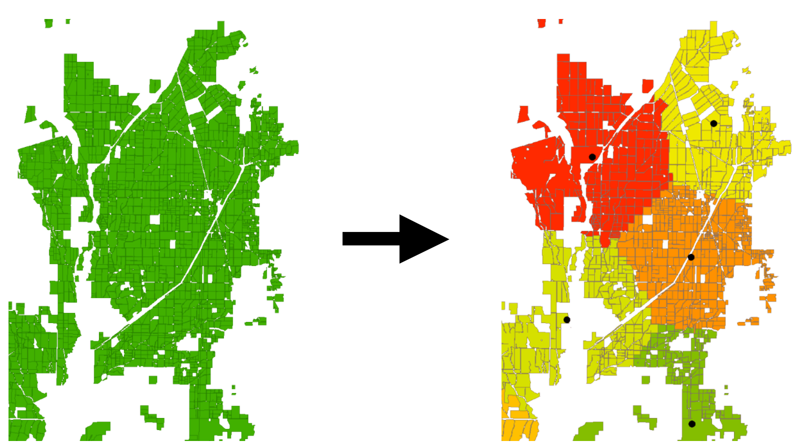
Field Clustering

In most cases, there will be an unnecessarily large number of fields for the purpose of the modeling exercise. The representation of the fields can be simplified by aggregating nearby fields into single supply point. Large numbers provide greater precision of results but bog down the optimization model. The key is to reduce the number of supply points to as few as possible without losing the geographic information. K-means clustering is used to accomplish this task.

Clustering is a method of data analysis that seeks to minimize the variation within grouped observations while maximizing the variation between the groups of observations. For geographic clustering, the cluster variables are the x and y coordinates of the fields. I exported the x and y coordinates of the fields into SAS statistical software where the FASTCLUS option is used to produce a chosen number of clusters.

Figure 5 gives a visualization of clustering. The original field data with many small fields is converted to five large field clusters. The geographic location to the field clusters is represented by the point at their centers.

Figure 5: Visualization of Field Clustering



Shortest-path Delivery Distances

Models of both feedstock delivery and hydrogen delivery need distances over the road network between the supply points and the sites and the sites and the demand centers. To calculate the delivery distances over the road network a "shortest path' algorithm was used within GIS. The algorithm used chooses the shortest distance over the road network based on distance not time.

SIMPLIFICATION MODELS

Selection of Potential Sites

In selecting potential sites, the researcher must look to find the most plausible locations to be optimal. In the hydrogen from biomass model, locations that would minimize the feedstock cost or minimize hydrogen delivery costs at different facility sizes are the sites that are most likely to be optimal. Additional sites representing the compromises between these sites should also be included.

An abstract model that can be used to aid in the selection of sites is a "torque" model. This model finds the "center of mass" for a given set of supply points or demand points. From GIS data the straight line distances between each point is calculated then a measure of "torque" described in Equation 20 is calculated for each point. The point with the lowest torque will be the "center of mass" or location where the delivery costs will likely be lowest.

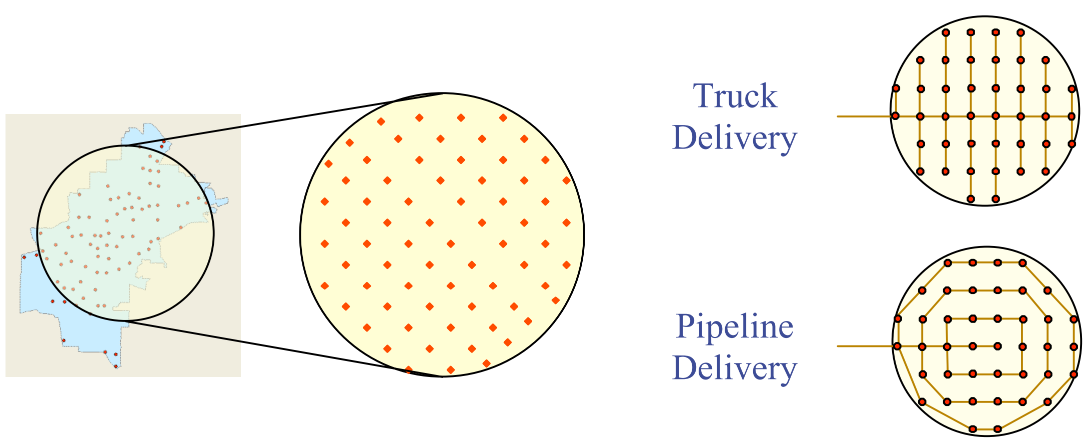
Equation 20

$$\tau_i = \frac{\sum_j x_j d_{ij}}{\sum_j x_j} \quad where: \begin{array}{l} x_j \equiv \text{quantity of supply or demand at point 'j'} \\ \mathrm{d}_{\mathrm{ij}} \equiv \text{distance between points 'i' and 'j'} \end{array}$$

Idealized City Model

Hydrogen demand is modeled at the city level for the purpose of this model. Hydrogen delivery within the city is simplified using idealized models of the city. The idealized city model reduces the distribution of refueling stations within the cities to a generic uniform distribution over a simplified city that is of equal area of the real city but is a circle instead (this is demonstrated in Figure 6). The delivery distances for trucks can be reduced to a simple equation of the radius of the city and the number of stations in the city ($d = 1.42*r_{city}*\#\_stations$). The intracity pipeline network length can also be expressed with a simple equation ($d = 2.43*r_{city}*\#\_stations^{0.4909}$). Idealizing local hydrogen delivery is vital to reducing the computational difficulties. The idealized city model used in the work was developed and used in earlier work by Yang and Ogden (2007).

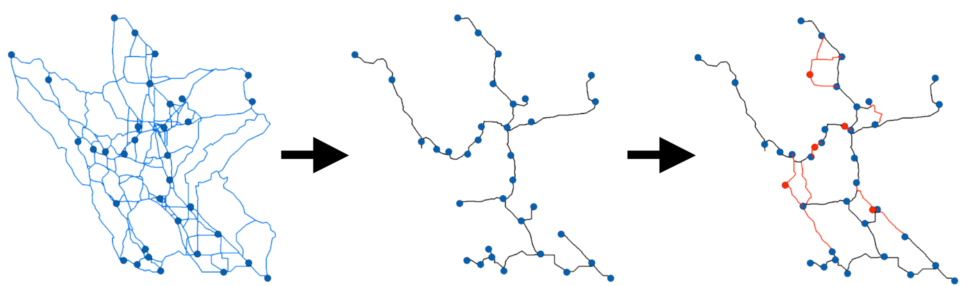
Figure 6: Visual of Idealized City Model



Modified Minimum Spanning Tree Intercity Pipeline Network

Binary variables are expensive in terms of computational requirements because they are not continuous, which requires a series of approximations to find the solution. Representing the pipeline network as a set of binary links causes computational difficulties when all possible links are considered as potential pipeline links. In reality, many of the links will never be chosen in an optimal solution. In a preprocessing step, I reduced the potential pipeline links to only those that are likely to be in an optimal solution. First, a minimal spanning tree algorithm is used to link together the demand clusters. Then in GIS, I added links between this network and the conversion sites as well as links that provided missing connectivity.

Figure 7: Visual of Pipeline Network Reduction



Logistics of Inter-software Modeling

Six different software packages were used in implementing the model. This could be reduced in some cases by converting a few of the steps to be performed in ArcGIS. Most communication between programs was through comma or space delimited text files to transfer data. The feedstock resource maps were produced using ArcView 3.1. Hydrogen demand scenarios were produced in ArcGIS 9. Clustering analysis was performed in SAS statistical software. Once cluster labels were added in ArcView the aggregating of field data took place in ArcView. The torque model was implemented in MatLab with outputs to

ArcGIS 9 for final site preselection. Shortest path routing was performed in ArcView 3.1 using the scripts of the HYSS 1.0 model (Ory *et al.*). The minimal spanning tree algorithym for pipeline network reduction was performed in Microsoft Excel with output to ArcGIS 9 for visual link additions. The data was then entered into the GAMS model.

The data entering the GAMS MINLP model is as follows with all data in the form of space delimited text files from ArcView 3.1.

- Feedstock yields of each clustered field
- Hydrogen demand cluster demands and idealized radius
- Distances between clustered fields and sites, and sites and demand cluster.
- Pipeline network link lengths for reduced network

The engineering-economic cost data and idealized city model are embedded in the model as the cost equations that make up the objective function. Results are exported to Excel and ArcGIS 9 for display. For the ArcGIS 9 display of results, I manually selected the optimal choices from the initial choice data sets. This could be automated.

Case Studies

Introduction to Case Studies

This chapter gives a detailed description of a set of case studies using rice straw in California's Sacramento Valley for the production of hydrogen for use as a transportation fuel. Four separate rice straw availability scenarios are matched with four different hydrogen demand scenarios to produce 16 case studies using base case cost data. Sensitivity analysis is then performed on the economic parameters.

Rice straw availability is modeled as a percentage of the straw harvested on every field. The fraction of rice straw harvested is assumed to be spatially uniform. For example, if 50% of rice straw production is harvested, fields in both Yolo and Colousa counties will yield 3.01 tonnes per acre. Using current harvest methods, net straw harvest is usually between 40 and 60 percent of the gross straw production (Jenkins *et al.* 2000). In our scenarios 5%, 25%, 50% and 75% of gross rice straw is harvested and available for hydrogen production. 50% yield is considered the most likely result with current technology. 75% yield is a very high yield with current harvest technology and can be considered an improved technology case. 25% yield represents a very low yield and can be considered with the 5% yield to represent a smaller resource with the same geographic distribution.

The case study area has been limited to Northern California. In this study Northern California is considered to be California cities north of Merced (see Census data map at end of chapter Figure 11). Hydrogen demand scenarios are produced for 1, 10, 25, and 50% of total light duty vehicle fleet in the urban areas using hydrogen.

The base case engineering-economic costs are described below. In general, the rice straw harvest, transport and storage cost come from Jenkins *et al* (2000). The hydrogen production costs are derived from Larson *et al* (2005). The hydrogen terminal and delivery costs are mostly from the Department of Energy's Hydrogen Analysis (H2A) spreadsheets (DOE 2006).

Sixteen case studies are presented here for all combinations of rice straw availability and hydrogen demand with base case engineering-economic costs. Sensitivity analysis on engineering-economic parameters is performed for each hydrogen demand scenario using the 50% rice straw availability.

Table 5: Matrix of Case Studies Performed

		Rice Straw Availability			
Hydrogen Demand		5%	25%	50%	75%
	1%				
	10%				
	25%				
	50%				

HYDROGEN DEMAND DATA

Input Data

The original data used to produce the hydrogen demand maps is population data from the year 2000 U.S. Census. A map of the population density given by the census data is shown in Figure 11. The population density categories on the map correspond to the hydrogen demand density needed for each of the demand scenarios.

Calculation of Hydrogen Demand

The demand maps were derived in the manner explained in the Methodology chapter by Nils Johnson (Johnson 2006). The maps produced were for 1%, 10%, 25%, and 50% of light duty vehicles in the demand clusters operating on hydrogen. Seven-tenths of a vehicle is assumed per capita, with each vehicle driving 12,000 miles per year at 55 miles per kilogram hydrogen. This is different from a percentage of the total Northern California light duty vehicle fuel demand because in areas outside of the demand clusters all vehicles use fuels other than hydrogen. The demand density filters and aggregate cluster demand filters are given in Table 6. Census blocks need to have a demand density greater than the demand density filter in order to be considered for the creation of a demand cluster. A cluster must have a total demand at least the size of the aggregate demand filter to be considered a viable cluster.

Table 6: Parameters for Demand Scenario Creation

	Demand Density Filter	Aggregate Demand Filter	Buffer Width
1% Demand Scenario	10 kg/day/km2	300 kg/day	5 km
10% Demand Scenario	100 kg/day/km2	500 kg/day	5 km
25% Demand Scenario	100 kg/day/km2	1500 kg/day	5 km
50% Demand Scenario	100 kg/day/km2	1500 kg/day	5 km

Hydrogen Fractional Demand Scenarios

Maps of the hydrogen demand clusters for the four different scenarios are given in Figures 12 - 15 at the end of the chapter. Table 7 gives some descriptive statistics for the demand scenarios generated. The average demand density within the demand clusters (excluding the zero hydrogen demand rural areas) are extremely low in the 1% case due to the low threshold filters applied in that case (see Table 6). There are more demand clusters in the

10% demand scenario than the 25% and 50% demand scenarios because the aggregate demand filter was set lower for the 10% scenario. It is important to note that for all but the 1% scenario more hydrogen is demanded than there is rice straw to supply the hydrogen. In the scenarios where demand is greater than the feedstock supply, the hydrogen demand will only partially be met with rice straw-based hydrogen with the rest coming from a generic backstop hydrogen supply source. The reported costs in the analysis are only for the rice straw-based fraction of the hydrogen demand.

Table 7: Statistics on Hydrogen Demand Scenarios

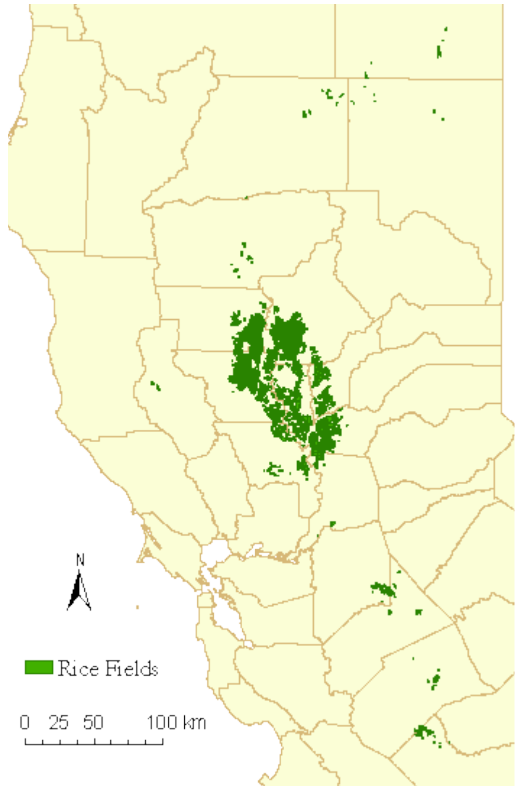
	Total Demand	Avg. Demand Density	Number of Demand Clusters
1% Demand Scenario	39,090 kg/day	6.5 kg/day/km^2	13
10% Demand Scenario	412,407 kg/day	61.9 kg/day/km^2	34
25% Demand Scenario	994,294 kg/day	132 kg/day/km^2	23
50% Demand Scenario	2,015,536 kg/day	226 kg/day/km^2	29

RICE STRAW DATA

California Rice Straw General Statistics

In the year 2003, California farmers planted approximately 207,000 hectares (2070 km2) of rice in the Sacramento Valley. The distribution of the fields is shown in Figure 8. Along with the rice crop, these fields produce 7.44 dry tonnes of rice straw per hectare on average (von Bernath *et al.* 2004). The gross rice straw production in California is approximately 1.8 million dry tonnes which could yield 130 million kilograms of hydrogen per year, 356,000 kilograms per day, at an assumed conversion efficiency of 63%. Limitations of the harvesting equipment reduce the harvestable rice straw to 40% to 60% of the gross straw production (Jenkins *et al.* 2000). For this study, I assume that 50% of the straw can be harvested for the base-case, which is consistent with the assumptions given by von Bernath *et al* in their biomass resource assessment for the California Energy Commission (2004).

Figure 8: Rice Fields in California



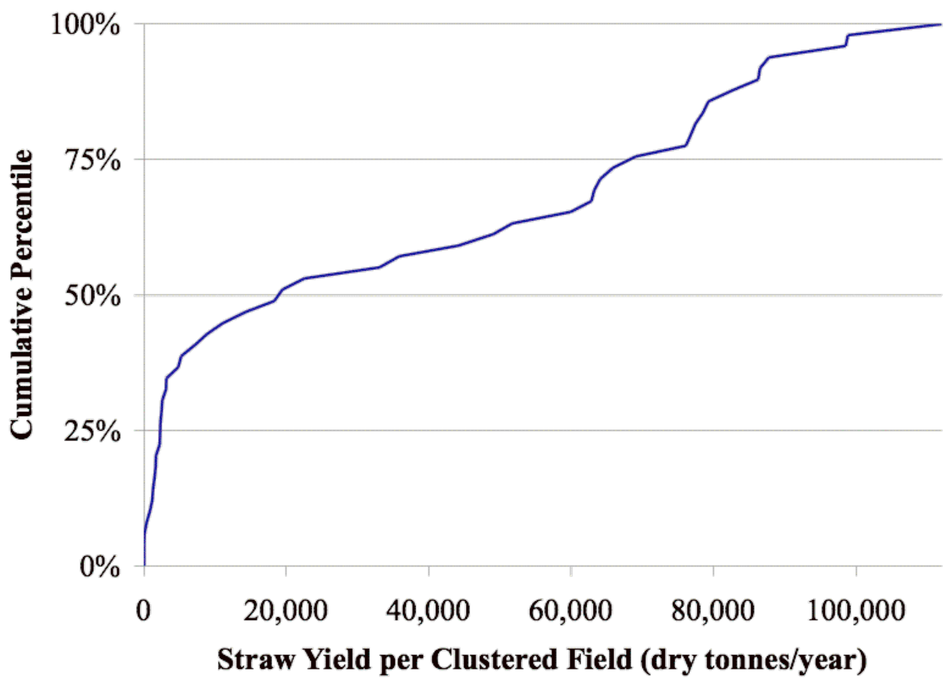
50 Clustered Fields

The above map uses data from the California Department of Water Resources and has a spatial resolution beyond what is necessary for the purpose of this study. This data shows greater than 6,000 distinct rice fields many separated by less than 100 meters. Cluster analysis is used, as explained in Chapter 3, to reduce the number of distinct fields to 50. Figure 16 shows which fields are clustered together along with the centroids for each clustered field, which is used to represent the location of fields in that cluster. The centroids are also the locations of the distributed rice straw storage facilities.

These 50 fields are not uniform by any measure. The smallest field is 150 meters across while the largest is over 11 kilometers across.

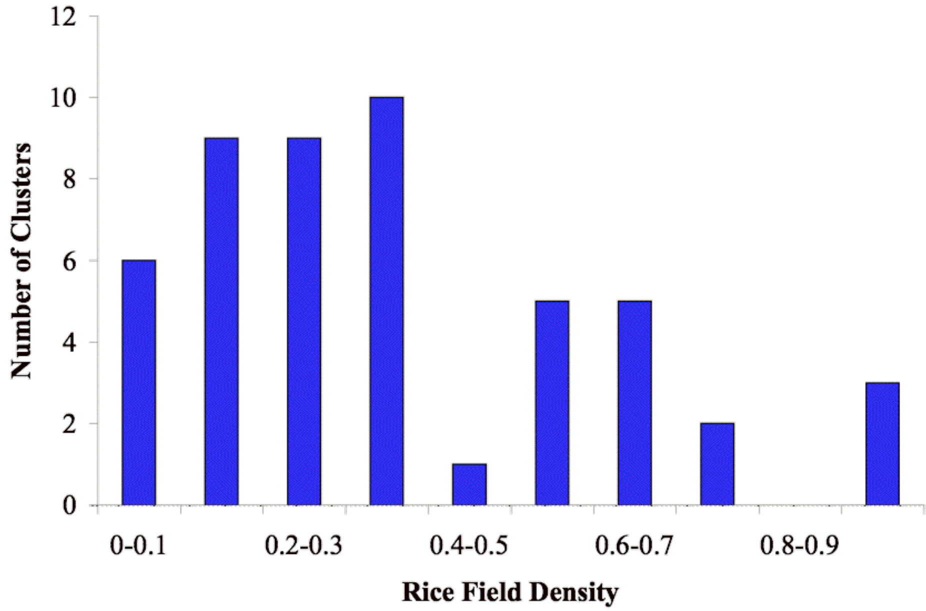
Chart 4 shows the distribution of straw yields per field. About 25 fields have straw yields less than 20,000 tonnes per year and 10 fields have yields greater 75,000 tonnes per year.

Chart 4: Cumulative Percentile v Field Gross Straw Yield



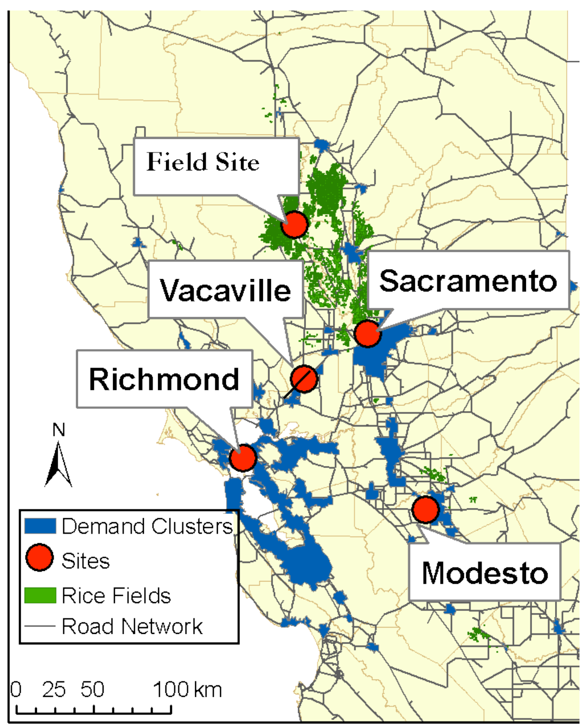
The fraction of the land encompassed by the cluster that is actually rice fields is widely varying as well. Since many fields are aggregated together into one field cluster, land of other uses is stranded in between. The fraction of the field cluster that is planted in rice is found by defining the convex hull around the clustered fields as the cluster area and calculating the density of rice fields within the convex hull. The histogram of this fraction is given in Chart 5. Thirty-five out of the fifty field clusters have less than 50% of their land planted in rice.

Chart 5: Histogram Depicting Fraction of Cluster Area that is Rice Fields



CHOICE OF GASIFICATION SITES

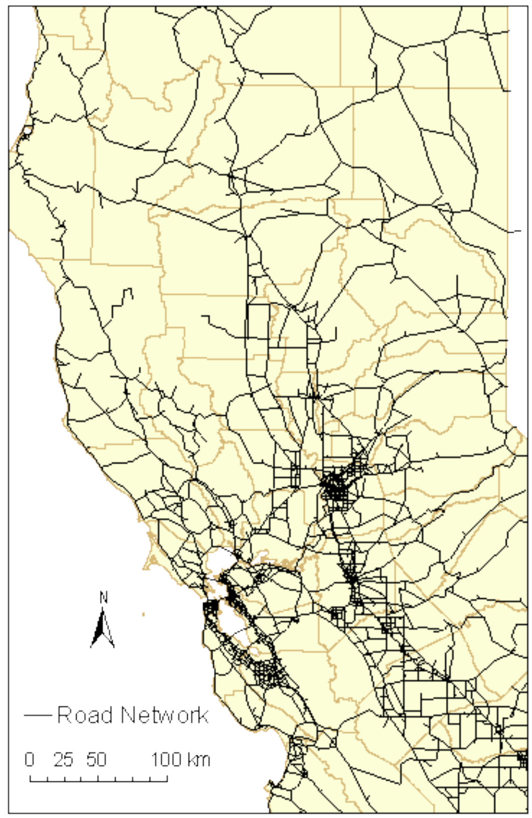
Figure 9: Potential Facility Location



Potential sites were selected from an earlier analysis that used simplified engineering-economic models for single facility cost curves at each field and 10% hydrogen demand centroid (Parker 2006). For large facilities (hydrogen capacity > 80,000 kg/day), a site at the eastern edge of the San Francisco Bay Area was favorable. Smaller facilities (< 60,000 kg/day) favored a site on the Northern edge of Sacramento. Finally for moderately-sized facilities (60,000 - 80,000 kg/day), a site located to minimize straw collection costs was most attractive (labeled "Field Site"). Two other sites were added out of researcher curiosity. One near Vacaville was added as a compromise between the Sacramento and Richmond sites. Another was added near Modesto as a potential small facility utilizing local straw for a small local demand. Figure 9 shows these sites with respect to the rice fields and the demand clusters for the 10% demand scenario.

Road Network Data

Figure 10: Road Network



The road network used in this analysis is the "California Base" network from California Department of Transportation. This network consists of all interstates, major highways and major urban arterial roads. It was chosen because it gave good resolution without overwhelming the shortest path algorithm.

On-road distances are found between all field centroids and all sites, all sites and all cities, and between all cities using a shortest path algorithm described in Chapter 3. This distance data is used as an input in the cost functions discussed later in this chapter.

All field cluster centroids are not located directly on the road network. This problem is handled by calculating the distance from the centroid to the nearest road and adding that distance to the transportation distance to any site. The largest off-road distance is 9.15 km.

COST DATA

Introduction

The model used in this analysis decides the optimal configuration and spatial layout of a series of "black-box" components. Each component, rice straw harvest, storage, transport, hydrogen production, hydrogen terminals, hydrogen distribution, and refueling stations, has a cost function that represents a number of assumptions in the design of that particular component and whether the design changes with the size of the component. The optimization model presented here does not attempt to optimize within the components but rather to optimize the set of components. The assumptions used to produce the "black-box" cost functions are described below.

The cost data used for this analysis comes from three main sources, Jenkins *et al* (2000) for all costs dealing with rice straw, Larson *et al* (2005) for the costs associated with the hydrogen production facility, and the Department of Energy's H2A Analysis spreadsheets for all costs involved in the distribution of hydrogen to the end-users (DOE 2006). In a few instances, I have changed a few assumptions in producing the cost functions or made an extension to the data that is available through the above sources. The exceptions are noted in the following description of the cost functions.

Cost Calculation Definitions

Simple annualized cost calculations are used where disaggregated data is available. Constant year 2005 dollars are used for all costs. The generic form of the annual cost (AC) equation is:

$$AC = \left(\frac{irr}{1-(1+irr)^{-lt}} + O\&M \right) \cdot \sum_i IF^i \cdot C_b^i \cdot \left(S_x^i \big/ S_b^i \right)^{\alpha^i} + \sum_j VC_j \cdot annual\_production$$

where: irr is the real internal rate of return on investment and lt is the lifetime of the component. O&M is the fraction of initial capital cost required for fixed operating and maintenance costs. IF^i is the installation factor that is a multiple of the individual component capital costs used to approximate the costs of engineering, balance of plant, overhead, and interest accrued during construction. Some component costs have the installation factor already included. In such cases IF is set to 1. C_b^i, S_x^i, S_b^i, and α^i represent the capital cost of a component with scale economies. C_b^i is the base cost, S_x^i is the actual size of the component in the analysis, S_b^i is the base size, and α^i is the scaling factor. The scaling factor is typically between 0.5 and 1, with lower values representing stronger scale economies. VC_j is a variable cost which is accrued for each unit of throughput and includes costs such as feedstocks, net electricity costs and distance dependent costs in deliveries.

Other cost factors involved are the capacity factors of each component, the price of diesel fuel and the price of electricity. The capacity factors give the fraction of time that a component is used to its full capacity.

Rice Straw Harvest

Description

Rice straw is harvested after the completion of the rice harvest. Straw is either raked or swathed depending on the stubble height post rice harvest. Swathing cuts the stubble closer to the ground and windrows the straw, leading to greater straw yield than raking systems. Swathing is commonly employed when the stubble height is over 0.15 meters. The straw is baled into large Hesston-type bales (1.2m x 1.2m x 2.4m) weighing approximately 600 kg per bale. The bales are retrieved from the field using stackwagons and taken to the local storage at the centroid of the field cluster. The stackwagon travels a maximum of 2 kilometers to the roadside as reported in Jenkins *et al*. The stackwagon then travels at a speed of 25 mph to the centroid over roads.

Costs

Costs provided by Jenkins *et al* are not disaggregated in a way that will allow for reducing the costs to capital, labor, and maintenance costs. I will therefore use their assumptions for the rice straw costs. Labor is paid at a rate of \$8.50 h^{-1}, straight-line depreciation is used with a real internal rate of return on capital of 8.2%, insurance and taxes are 0.7% and 1% of the machine costs respectively. The harvested straw has an average moisture content of 15%. The costs are reported as wet tonnes not dry tonnes. Five-eighths of the straw is assumed to use raking for windrowing with the remainder using swathing. The one cost that is disaggregated is diesel fuel use. Assuming that a 120-hp tractor is used for all operations, fuel use is calculated by the time required for each operation and a fuel use of 22.45 L/h. Costs have been increased by a factor of 1.16 to adjust year 1997 dollars to year 2005 dollars.

Table 8: Rice Straw Harvesting Costs

	Base Cost	**Fuel Use**
Raking	\$1.40/wet tonne	0.85 L/wet tonne
Swathing	\$5.16/wet tonne	2.71 L/wet tonne
Baling	\$4.96/wet tonne	1.43 L/wet tonne
Roadsiding	\$(3.68 + 1.05*r[6])/wet tonne	(0.75+0.30*r[6]) L/wet tonne
Total	***\$(11.45 + 1.05*r)/wet tonne***	***(3.73+0.30*r) L/wet tonne***

[6] r denotes the radius of the field cluster.

Rice Straw Storage

Description

Rice straw is assumed to be stored in pole barns that are located near the rice field supply points. The bales are stacked 8-high in the barn, yielding 1.67 wet tonnes of storage per square meter. The entire rice straw harvest would need approximately 54 hectares of pole barn storage or about 0.03% of land devoted to rice growing. The straw is stored in the pole barns for at most 11 months of the year due to the once a year harvest season. 4.2% of the straw is lost during storage (Summers *et al.* 2001).

Costs

The pole barns are assumed to have a 15 year lifetime. Jenkins *et al* report costs with salvage values of 15% or 30%. Since no other components in the model have a salvage value, the salvage value has been removed from the calculations. Otherwise the assumptions above for the harvest costs are the same assumptions for the storage costs. The storage cost is $7.50 per wet tonne of rice straw.

Rice Straw Transport

Description

Double drop-bed trailers with a payload of 19 tonnes transport the rice straw from the storage barns to the production facility. The trucks are loaded and unloaded by fork-lifts.

Costs

The truck costs follow the same assumptions as stated above. The cost of diesel for the trucks is disaggregated assuming a fuel economy of 4.4 mpg for the trucks. The costs reported are based on the one-way distance and are simply multiplied by two to get the roundtrip cost.

Table 9: Rice Straw Transport Costs

	Base Cost	Fuel Use
Trucking	$0.06/wet tonne-km	0.03 L/wet tonne-km
Loading/Unloading	$4.16/wet tonne	1.18 L/wet tonne

Hydrogen Production Facility

Design

The gasification facility uses the GTI gasifier to produce hydrogen and a small amount of electricity with all carbon dioxide vented to the atmosphere. All energy for the conversion process comes from the rice straw feedstock. At the end of the conversion process, hydrogen is passed to the terminal at a pressure of 19.5 atm. This facility is modeled after the MAX-H2-VENT facility design in Larson *et al* (2005). The gasifier in the Larson design has a maximum capacity of 2,880 wet tonnes per day. For facilities of greater size, the facility is designed with two gasifier trains. The actual cost function has a discontinuity in it. The facility is modeled here with a smooth cost curve that is fit to Larson's costs over the range of 0 – 5,000 wet tonnes of biomass per day[7]. Five days of rice straw storage is assumed for the production facility to buffer against disruptions in supply between the distributed storage points.

The gasification facility produces both electricity and hydrogen. The facility produces hydrogen at 63% higher heating value efficiency. Given 15% moisture content and rice straw's HHV of 16.28 GJ/dry tonne, 61.35 kilograms of hydrogen and 181.85 kilowatt-hours of electricity are produced per wet tonne of rice straw consumed by the facility.

[7] See Chart 1 in Appendix A for curve fit.

Capital Costs

Table 10: Gasification Facility Capital Costs

	C_b	S_b	α	Range	IF	Lifetime
Gasification Facility	$197,800,000	2,000 wet tonnes straw	0.712	400 – 5,000 wt/d	1	15 years
Onsite Straw Storage	$45.22	1 tonne straw	1	4,000 – 20,000 Mg	1	15 years

Operating Costs

Table 11: Gasification Facility Operating Costs

	Cost	Comment
Fixed O&M Gasifier	5% Initial Capital	
Variable Storage Costs	$1.85/tonne straw	Non-capital portion of storage costs in Jenkins *et al* assumed to be variable
Electricity	-2.63 kWh/kg H_2	Electricity is co-produced with hydrogen leading to a credit

Gaseous Hydrogen Terminal

Design

The terminal for compressed gas trucks needs hydrogen storage, hydrogen compressors for both truck and storage pressures and truck loading bays. In the design used here, the terminal is designed to operate at a 70% capacity factor for truck loading. Storage is sized at one day of maximum load. H2A assumes 3 days which we considered more than necessary.

Three truck loading compressors are sized to handle half the maximum load of the terminal with one acting as a backup. Two storage compressors are sized to handle half the hydrogen production facility's capacity to allow for fluctuations in the demand on the terminal with one acting as a backup. This is different from the H2A assumptions where the storage compressors were sized to fill 3 days (maximum load) of storage in 2 days. The H2A design results in 2 oversized compressors which are used at a combined capacity factor of about 2.5%.

The hydrogen comes into the terminal at 19.5 atm. The pressure needs to be increased to 180 atm for loading onto trucks and to 305 atm for storage. Both the truck compressors and the storage compressors are 5-stage compressors with isentropic efficiency of 80%. Truck compressors require 44.871 kW per tonne of hydrogen per day capacity while the storage compressors require 67.309 kW per tonne of hydrogen per day capacity.

In operation, 90% of the hydrogen produced is pumped directly into the trucks with the

Note on Compressor Sizing

The power requirement of all compressors in kW is given by the following equation:

$$\wp = \frac{\bar{\chi}}{\eta_{isentropic}}\left(\frac{Q}{2.0158}\right) R T_i n \frac{C_p/C_v}{\left(C_p/C_v - 1\right)}\left(P_f/P_i\right)^{\frac{(C_p/C_v - 1)}{nC_p/C_v}}$$

where χ is the mean compressibility factor for the given pressures, $\eta_{isentropic}$ is the isentropic compression efficiency of the compressor, Q is the hydrogen flow rate in kg/s, R is the gas constant, T_i is the initial temperature in Kelvin, n is the number of stages of the compressor, C_p/C_v is the ratio of specific heats, P_f and P_i are final and initial pressures and. The table below gives the factors that are common for all compressors in the analysis.

R	8.3144
Ti	297.15 K
Cp/Cv	1.4

remaining 10% being pumped to storage pressure

Capital Costs

The capital costs come directly from H2A. The sizing and capital costs must be combined to find the cost of the compressors. For example, a 50 tonne per day terminal would require three 35.7 tonne per day truck compressors and two 25 tonne per day storage compressors. The truck compressors would require 1.60 MW each and the storage compressors would require 1.68 MW each. This would lead to a capital cost of $7.2 million per truck compressor and $7.4 million per storage compressor.

The storage, piping, and truck bays are sized at 1.43 the hydrogen production plant capacity (70% capacity factor). So for the same 50 tonne per day terminal S_x for storage, piping and truck bays is 71.43 tonnes of hydrogen.

Table 12: Compressed Gas Tuck Terminal Capital Costs

	C_b	S_b	α	Range	IF	lifetime
H_2 Compressor	$153,360,000	5 MW	0.6674	0.3 - 20 MW	1	20 years
Gaseous H_2 Storage	1.1*$818	1 kg H_2	0.8	None given	1.76	20 years
Piping etc.	$277,270	100 Mg H_2/day	0.847	30 – 300 Mg/day	1.76	20 years
Truck Bays	$1,593,000	100 Mg H_2/day	1	30 – 300 Mg/day	1.76	20 years

Operating Costs

Table 13: Compressed Gas Truck Terminal Operating Costs

	Cost	Comment
Fixed O&M	12% of Initial Capital	Covers labor, overhead, insurance, taxes, licensing, maintenance, and repair
Electricity	0.758 kWh/kg H_2	Electricity use by compressors

Compressed Gas Trucks

Design

The hydrogen tube trailers are filled at the terminal and transported to the refueling stations. The trailer is dropped off at the station to be used as on-site storage and an empty trailer is picked up by the truck for a return to the terminal.

Component Sizing

The number of truck cabs and trailers needed is dependent on the time it takes each to cycle through a full load of hydrogen and the amount of hydrogen delivered per truckload. The 180 atm tube trailers have an effective capacity of 280.3 kg of hydrogen per load. The trailers require 6 hours to refill at the terminal plus an additional hour and a half at the terminal for drop-off/pick-up. For average 40 kilometer one-way delivery distances, the trailers will spend approximately one and a half hours in the roundtrip transit with an additional 1.5 hours of drop-off/pick-up time at the station. The trailer will stay at a station for between 12 and 36 hours. For simplification, I assume that the total cycle time for a compressed gas trailer is approximately 24 hours and that each station will require N_{trl} trailers (Equation 21) to have a full day of storage plus one trailer being refueled at the terminal. This is a conservative estimate especially for systems with many stations. The truck cabs accompany the trailers for all steps above except the refill time and the station time, giving the cabs a cycle time of 4.5 hours. One truck can deliver on average 1,465 kg of hydrogen per day accounting for the 98% availability of the truck. The total number of trucks required for a terminal (N_{trk}) is given in Equation 22.

Equation 21

$$N_{trl} = \frac{Station\_Capacity}{280.3} + 1$$

Equation 22

$$N_{trk} = \frac{\text{Terminal\_Capacity}}{\text{1,465 kg hydrogen}}$$

Capital Costs

Table 14: Compressed Gas Truck Capital Costs

	Capital Cost	Lifetime
Truck Cab	$100,000	5 years
Tube Trailer	$165,000	20 years

Operating Costs

Table 15: Compressed Gas Truck Operating Costs

	Cost	Comment
Labor/overhead	1.5*$171,696*#_trucks	
Taxes	1.5% Initial Capital	
Per km costs	$0.1488 per km	Covers insurance, taxes, licensing, maintenance and repairs.
Diesel	0.1036 gal/km	

Total yearly travel distance is given by Equation 23 and depends on the number of trips that are needed between the terminal and the station and the roundtrip distance between the two. The distances for all stations associated with the terminal are summed together to give the following formula.

Equation 23

$$\text{Total yearly distance} = \sum_{\text{k}} 2\text{d}_{\text{jk}} \cdot \left(\frac{Station\_Demand_k * 365}{280.3 \cdot 0.995} \right)$$

Compressed Gas Truck Refueling Stations

Design

The design for hydrogen stations served by compressed gas trucks is based on the H2A design for a 100 kg capacity station served by compressed gas trucks. Even thought he H2A design is for a small station and the extrapolation to larger stations will not likely provide the most accurate cost estimations, extrapolation needed in order to have variable station sizes in the model. The stations are limited to be less than 560.6 kg per day average daily demand by recommendation that a refueling station requiring more than 2 deliveries per day would face overwhelming logistical challenges.

The refueling station is assumed to have a single 425 atm hydrogen dispenser incorporated into an existing gasoline station. The station is designed to operate at a 70% capacity factor. Three compressors, a storage tank and the dispenser are the major components to the station.

Component Sizing

The three compressors are sized to accommodated half of the maximum demand (0.72*average demand each). Capital costs of small compressors are given in H2A in terms of hydrogen flow rate so the power requirement is not necessary to calculate the size. But for general information, it is 98.89 kW/ tonne of hydrogen capacity for a 4-stage compressor with an isentropic efficiency of 65%.

The 425 atm storage tank is sized to be 0.54 of the average demand for the station. A single dispenser is at every compressed gas hydrogen station regardless of size.

Capital Costs

Table 16: Compressed Gas Refueling Station Capital Costs

	C_b	S_b	α	Range	IF	Lifetime
H_2 Compressor	\$13,000	70 kg H_2/day	0.88	70 – 560 kg/day	1.45	10 years
Gaseous H_2 Storage	\$11,450	14 kg H_2	1	>14 kg	1.45	20 years
Dispensers	\$26,880	1 dispenser	-	<500 kg/day	1.45	10 years

Operating Costs

Table 17; Compressed Gas Refueling Station Operating Costs

	Cost	Comment
Yearly Land Rent	$[8.39*(avg demand) + 15,368]	Derived from the land rents for 100 kg/day and 1500 kg/day gaseous stations in H2A
Fixed O&M	10.36% Initial Capital	Covers labor, overhead, insurance, taxes, maintenance and repairs
Electricity	1.246 kWh/kg hydrogen	

Liquid Hydrogen Terminal

Design

The liquid hydrogen terminal is designed to operate with a 70% capacity factor. One large liquefier, 2 liquid hydrogen pumps, truck bays, and 5 days of storage are the main components of the terminal.

Component Sizing

The liquefier is sized to meet the maximum flow rate of the terminal which is 1.43 times the hydrogen production facility capacity. Liquid hydrogen storage consists of 5 days of the maximum terminal flow rate. A correction factor of 1.0125 is used in the storage sizing to account for hydrogen boil-off of 0.25% per day. Each liquid pump is sized to handle 75% of the peak hydrogen flow rate.

Capital Costs

Table 18: Liquid Terminal Capital Costs

	C_b	S_b	α	Range	IF	Lifetime
Liquefier	$95,184,250	100 tonnes/day	0.523	33 - 450 Mg/day	1.76	20 years
Liquid H_2 Storage	$4,306,036	100 tonne/day	0.824	30 – 450 Mg/day	1.76	20 years
Pump/piping /etc[8]	$2,159,175	100 tonne/day	0.96	30 – 300 Mg/day	1.76	20 years

Operating Costs

Table 19: Liquid Terminal Operating Costs

	Cost	Comment
Fixed O&M	4% Initial Capital	
Electricity	9.76 kWh/kg hydrogen	Based on H2A 100 tonne/day liquefier, efficiency scaling not included in analysis

Liquid Hydrogen Tanker Trucks

Design

The liquid hydrogen tanker trucks operate as one unit delivering a full load of hydrogen to a single station then returning empty to the terminal to be refilled. Filling the tanker truck at the terminal takes 3 hours, unloading time at the station takes 3.5 hours, and on-road time will average around 1.5 hours per roundtrip. This gives an average cycle time of 8 hours or 3 loads per day. A liquid truck will take 4,142 kg of hydrogen from the terminal and deliver 3,891 kg to the station with the remainder lost in loading/unloading and boil-off.[9] The number of trucks and trailers needed are allocated to the terminal following Equation 24.

Equation 24

$$\#\ \text{of } LH_2 \text{ trucks needed} = \frac{\text{Terminal Capacity}}{12{,}178 \text{ kg/day}}$$

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[8] Fitted curve to H2A cost data. See Charts 17 in Appendix A

[9] See page 78 for discussion of treatment of hydrogen losses in the model.

Capital Costs

Table 20: Liquid Truck Capital Costs

	Capital Cost	Lifetime
Truck Cab	$100,000	5 years
Tanker Trailer	$625,000	20 years

Operating Costs

Table 21: Liquid Truck Operating Costs

	Cost	Comment
Labor and Overhead	1.5*$171,676*#_trucks	The 1.5 factor indicates the 50% overhead on labor
Taxes	2%Initial Capital	
Per km costs	$0.1488/km	Covers insurance, taxes, licensing, maintenance and repairs.
Diesel	0.1036 gallons/km	

Total yearly travel distances are calculated from the number of trips that are needed between the terminal and the station and the roundtrip distance between the two. The distances for all stations associated with the terminal are summed together using Equation 25. The factor of 0.989 accounts for hydrogen losses at the refueling station.

Equation 25

$$\text{Total yearly distance} = \sum_{k} 2\mathrm{d}_{jk} \cdot \left(\frac{Station\_Demand_k * 365}{3{,}891.45 \cdot 0.989} \right)$$

Liquid Truck Refueling Stations

Design

The design of the hydrogen refueling station served by liquid hydrogen trucks is modeled after the 100 kg/day and 1,500 kg/day station designs in H2A. The stations in this work will range from 100 kg/day to 3,000 kg/ day. The costs are obtained by extrapolating from the values in H2A. One major modification is that for the single load scenario of trucking to work 3,891.5 kg of effective liquid storage space must be available when the trucks arrive. For this reason the liquid hydrogen storage at the station is sized to be 4,324 kg plus a third day of the average station demand. 425 atm compressed gas storage of hydrogen will be sized at a third of the average station demand. A dispenser will be included for every 350 kg of average station demand. The station will also have 2 liquid hydrogen pumps sized at 2.29 the average station demand each and an evaporator.

Capital Costs

Table 22: Liquid Refueling Station Capital Costs

	C_b	S_b	α	Range	IF	Lifetime
Liquid H_2 Storage	$200,000	4,000 kg H_2	1	Price quote for 4,000 kg	1.26	20 years
Gaseous H_2 Storage	1.1*$818	1 kg H_2	1	None given	1.26	20 years
Dispensers	$26,880	1 dispenser	-		1.26	10 years
Liquid H_2 Pumps[10]	$[7.17*(avg demand) + 22,105]			100 – 1,500 kg/day	1.26	20 years
Evaporator[10]	$[5.17*(avg demand) + 7,558]			100 – 1,500 kg/day	1.26	20 years

Operating Costs

Table 23: Liquid Refueling Station Operating Costs

	Cost	Comment
Annual Land Rent	$[16.52*(avg demand) + 11,617]	Derived from the land rents for 100 kg/day and 1500 kg/day liquid stations in H2A
Fixed O&M	6.5% Initial Capital	Covers labor, overhead, insurance, taxes, maintenance and repairs
Electricity	0.33 kWh/kg hydrogen	

[10] Fitted curve to H2A cost data. See Charts 18 and 19 in Appendix A

Pipeline Terminal

Design

The pipeline terminal receives hydrogen at 19.5 atm. Its main function is to increase the pressure to 68 atm for pipeline distribution. Three compressors are employed to do this. Two compressors operate full time, sized at half the hydrogen production facility's maximum flow rate and one equally sized backup. One half of a day of hydrogen production is kept in storage at the terminal. Two compressors are required to increases the hydrogen to the 305 atm storage pressure. The storage compressors are sized at 10% of the production facilities maximum flow rate.

Component Sizing

The pipeline compressors are 3-stage compressors with an isentropic efficiency of 80%. Their power requirements are 24 kW/tonne hydrogen per day capacity each. The storage compressors are 6-stage compressors with an isentropic efficiency of 80%. Their power requirements are 58 kW/tonne hydrogen per day capacity each.

Capital Costs

Table 24: Pipeline Terminal Capital Costs

	C_b	S_b	α	Range	IF	Lifetime
H_2 Compressor	$153,360,000	5 MW	0.6674	0.3 - 20 MW	1	20 years
Gaseous H_2 Storage	1.1*$818	1 kg H_2	0.8	None given	1.72	20 years

Operating Costs

Table 25: Pipeline Terminal Operating Costs

	Cost	Comment
Fixed O&M • **Compressors** • **Storage**	 13.5% Initial Capital 4% Initial Capital	
Electricity	0.57 kWh/kg H_2	

Hydrogen Pipelines

Design

The pipeline network will follow the shortest path roadway links as described in the Methodology chapter for intercity connections. Intracity pipeline lengths will be determined by the idealized city model. All pipelines are modeled as having 12-inch diameter pipe. This is the maximum size needed in any scenario with hydrogen flow rates in the case studies. The per kilometer cost of pipelines below 12-inches in diameter are relatively constant so adding the complexity of pipe sizing to the model will not add much to the functionality of the model (Parker 2004).

Capital Costs

Rural and urban pipelines are differentiated in this work with urban pipelines costing 1.5 times the rural pipeline cost of equal length. Pipelines between demand clusters and between demand clusters and production facilities are considered rural pipelines. Pipelines within the demand clusters are considered urban pipelines.

Table 26: Pipeline Capital Costs

	Cost	IF	Lifetime
Rural H_2 Pipeline	1.1*$349,625/km	1	20 years
Urban H_2 Pipeline	1.5*1.1*$349,625/km	1	20 years

Operating Costs

Table 27: Pipeline Operating Costs

	Cost	Comment
Fixed O&M	4% Initial Capital	

Pipeline Refueling Stations

Design

The H2A design for pipeline supplied refueling stations has two sizes 100 kg/day and 1,500 kg/day. The design for stations used in this analysis is extrapolated from the 1,500 kg/day station. The hydrogen station is modeled as a fraction of an existing gasoline station (1-6 dispensers out of a total of 8). The 1,500 kilogram per day station is designed with three compressors capable of taking the 20 atm hydrogen from the pipeline and compressing it to 425 atm for dispensing to vehicles. A third of a day of high pressure storage is maintained at the station.

Component Sizing

The three compressors are sized to accommodate half of the maximum demand (0.72*average demand each). Capital costs of small compressors are given in H2A in terms of hydrogen flow rate so the power requirement is not needed to determine the cost. For general information, it is 89 kW/ tonne of hydrogen capacity for a 4-stage compressor with an isentropic efficiency of 65%.

The 425 atm storage tank is sized to be 0.34 of the average demand for the station. The number of dispensers is treated as a continuous function where a new dispenser is required for every 350 kg/day average station demand.

Capital Costs

The capital costs are taken from the 1,500 kg/day design in H2A. The range of station sizes have been extended beyond their intended use by making an assumption that the small scale compressors will scale in a similar manner as the large scale compressors seen in the terminals. In Appendix A Chart 2, the costs used here are compared with those of H2A and Yang and Ogden (2007). Cost here are higher than those of Yang and Ogden, passing through the H2A cost estimates, but follow a similar pattern of scaling.

Table 28: Pipeline Refueling Station Capital Costs

	C_b	S_b	α	Range	IF	Lifetime
H_2 Compressor	$173,878	1,000 kg H_2/day	0.667	100 – 1500 kg/day	1.27	10 years
Gaseous H_2 Storage	$11,452	14 kg H_2	1	>14 kg	1.27	20 years
Dispensers	$26,880	1 dispenser	-		1.27	10 years

Operating Costs

Table 29: Pipeline Refueling Station Operating Costs

	Cost	Comment
Yearly Land Rent	$[8.39*(avg demand) + 15,368]	Derived from the land rents for 100 kg/day and 1500 kg/day gaseous stations in H2A
Fixed O&M	6.3% Initial Capital	Covers labor, overhead, insurance, taxes, maintenance and repairs
Electricity	2.146 kWh/kg hydrogen	

A Note on Refueling Station Size

The station size for each demand cluster is determined to be the minimum of the maximum station size for the given scenario or the hydrogen demanded by that cluster. For a demand cluster with less than the maximum stations size for a given scenario only one smaller station is located in that cluster. The maximum station sizes are 150 kg/day for the 1% hydrogen demand scenario, 500 kg/day for the 10% hydrogen demand scenario, 1,000 kg/day for the 25% hydrogen demand scenario, and 1,500 kg/day for the 50% hydrogen demand scenario. This station sizing ensures that a reasonable number of stations are available for each demand scenario. The station sizes correspond to approximately 10% of stations in the 1%

demand case increasing to 30% of stations for the 10% demand case and up to 50% of stations in the 50% demand case. There is some variability between demand clusters in the percent of stations that are represented in each scenario.

A Note on Hydrogen Losses

There are hydrogen losses throughout the distribution system. Within the model these losses are treated as loss factors in the conservation of flow equations. Instead of all hydrogen entering the liquid terminal coming out of the liquid terminal, we have that 98.3% of the hydrogen comes out of the terminal. Table 30 below gives the hydrogen losses for each distribution system. Only the liquid truck distribution system explicitly accounts for losses in component sizing because the hydrogen losses for the other two systems are small compared to the built-in capacity factors of the system. The losses for the compressed gas truck and pipeline delivery modes are conservative estimates.

Table 30: Hydrogen Distribution Losses

	Compressed Gas Trucks	Liquid Trucks	Pipelines
Terminal	0.5%	1.7%	0.5%
Distribution	0%	6.1%	0.5%
Station	0.5%	1.1%	0.5%
Total	***1%***	***8.7%***	***1.5%***

NUMERICAL IMPLEMENTATION

Model statistics

Each of the four hydrogen demand cases represent a different model structure in terms of number of demand clusters and the links to them. Table 31 gives the statistics for each model. The binary variables are the number of potential pipeline links. Non-linear variables are variables that occur in terms of non-linear costs such as the gasifier capital cost.

Table 31: Model Statistics

	# variables	# non-linear variables	# binary variables	# equations
1% Demand	534	116	24	192
10% Demand	911	240	55	339
25% Demand	783	224	51	283
50% Demand	834	236	54	304

RESULTS

Base Case Economics Description

In running the 16 scenarios described in the matrix of Table 5, the base case economic parameters are used. The base case economic parameters use exactly the cost functions described in the Cost Data section. The other key economic assumptions are listed in Table 32.

Table 32: Base Case Economic Parameters

Real Internal Rate of Return	10%
Price of Diesel Fuel	$2.50 per gallon
Price of Electricity	$0.09 per kWh
Capacity Factor for Gasification Plant	0.9

Base Case Results

Summary tables of the results for each scenario are provided in the following pages.

The base case scenarios lead to a variety of optimal configurations. These span all modes of delivery and all but one of the potential conversion facility sites. All scenarios resulted in optimal designs with only one conversion facility. Levelized costs of delivered hydrogen ranged from $2.85 per kilogram in the 50% demand/75% rice straw scenario to $6.04 per kilogram in the 1% demand/5% rice straw scenario.

Compressed gas trucks were the hydrogen delivery mode of choice for all 1% demand scenarios and all but the high straw availability case of the 10% demand scenarios where liquid trucks were optimal. Pipeline delivery of hydrogen is optimal for all 25% and 50% demand scenarios.

Sacramento is the optimal location for a production facility in the most cases. All 50% demand scenarios site the conversion facility in Sacramento where all the hydrogen is consumed. When the supply of feedstock is less than Sacramento's 25% demand, Sacramento is chosen as the site of the production plant. The Richmond site (near large Bay Area demand) is favored for the 25% demand scenarios with 50% and 75% rice straw availability. In the 10% demand scenarios with compressed gas truck delivery the gasifier is located in Sacramento. The Field Site is optimal in the 10% demand scenario with 75% rice straw availability where liquid hydrogen delivery is the mode of choice. Sacramento is also the site for the 1% demand/5% feedstock scenario. Vacaville is the optimal location for the conversion facility in all other 1% demand scenarios.

The lowest cost system configurations also varied in the fraction of the available feedstock used. The 5% feedstock scenarios use all available straw in the least cost system for all hydrogen demands. All straw is also consumed in the 25% and 50% demand cases of the 25% feedstock scenarios but in the 10% demand case a few of the distant fields are deemed too costly to use. More fields are excluded in the 10%, 25%, and 50% demand scenarios as the size of the resource is increased. However, in the 10% demand/75% rice straw scenario with liquid hydrogen delivery all available straw is consumed.

Table 33: Summary of Optimal System Configurations

Hydrogen Demand	Rice Straw Availability				
		5%	25%	50%	75%
	1%	S	V	V	V
	10%	S	S	S	F
	25%	S	S	R	R
	50%	S	S	S	S

= Compressed Gas Truck Delivery
= Liquid Truck Delivery
= Pipeline Delivery
S = Facility located in Sacramento
V = Facility located in Vacaville
F = Facility located at the Field Site
R = Facility located in Richmond

Table 34: Summary of Results for Base Case 1% Demand Scenarios

Hydrogen Demand (% of LDV)	**1%**	**1%**	**1%**	**1%**
Feedstock Availability	**75%**	**50%**	**25%**	**5%**
Economics	**base**	**base**	**base**	**base**
Facility Location	**Vacaville**	**Vacaville**	**Vacaville**	**Sacramento**
Gasification Plant				
Capacity (kg/day)	43,871	43,871	43,871	18,732
Capital Cost ($)	$103,282,200	$103,282,200	$103,282,200	$56,328,065
Avg. Feedstock Cost at Plant ($/GJ)	$2.84	$2.89	$2.98	$3.00
Feedstock Costs ($/year)	$9,820,648	$9,981,885	$10,295,874	$4,430,510
Other O&M Cost ($/year)	$5,598,694	$5,598,694	$5,598,694	$3,001,959
Electricity Credit ($/year)	-$3,406,640	-$3,406,640	-$3,406,640	-$1,454,552
Compressed Gas Truck Terminal				
Capacity (kg/day)	56,406	56,406	56,406	24,084
Capital Cost ($)	$42,955,268	$42,955,268	$42,955,268	$23,490,747
Electricity Costs ($/year)	$983,165	$983,165	$983,165	$419,787
Other O&M ($/year)	$5,154,632	$5,154,632	$5,154,632	$2,818,890
Liquid Truck Terminal				
Capacity (kg/day)	-	-	-	-
Capital Cost ($)	-	-	-	-
Electricity Costs ($/year)	-	-	-	-
Other O&M ($/year)	-	-	-	-
Pipeline Terminal				
Capacity (kg/day)	-	-	-	-
Capital Cost ($)	-	-	-	-
Electricity Costs ($/year)	-	-	-	-
Other O&M ($/year)	-	-	-	-
Compressed Gas Truck Distribution				
Number of Trucks	39	39	39	17
Capital Cost ($)	$69,004,481	$69,004,481	$69,004,481	$29,463,231
Fuel Costs ($/year)	$3,641,227	$3,641,227	$3,641,227	$1,254,278
Other O&M ($/year)	$10,839,478	$10,839,478	$10,839,478	$4,455,586
Liquid Truck Distribution				
Number of Trucks	-	-	-	-
Capital Cost ($)	-	-	-	-
Fuel Costs ($/year)	-	-	-	-
Other O&M ($/year)	-	-	-	-
Pipeline Distribution				
Length of Pipeline (km)	-	-	-	-
Capital Cost ($)	-	-	-	-
O&M ($/year)	-	-	-	-
Refueling Stations (150 kg/day)				
Number of Comp. Gas Truck Stations	261	261	261	111
Number of Liquid Truck Stations	-	-	-	-
Number Pipeline Stations	-	-	-	-
Capital Cost ($)	$53,218,819	$53,218,819	$53,218,819	$22,723,137
Electricity Costs ($/year)	$1,600,003	$1,600,003	$1,600,003	$683,161
Other O&M Costs ($/year)	$9,846,180	$9,846,180	$9,846,180	$4,204,078
Total Delivered Hydrogen	14,267,923	14,267,923	14,267,923	6,092,055
Vehicles Served	65,389	65,389	65,389	27,920
Total Capital Cost	$268,460,769	$268,460,769	$268,460,769	$132,005,181
Capital Cost per Vehicle Served	$4,106	$4,106	$4,106	$4,728
Levelized Cost of Delivered H_2	$5.52	$5.53	$5.55	$6.04

Table 35: Summary of Results for Base Case 10% Demand Scenarios

Hydrogen Demand (% of LDV)	**10%**	**10%**	**10%**	**10%**
Feedstock Availability	**75%**	**50%**	**25%**	**5%**
Economics	**base**	**base**	**base**	**base**
Facility Location	***Field Site***	***Sacramento***	***Sacramento***	***Sacramento***
Gasification Plant				
Capacity (kg/day)	280,979	182,502	92,999	18,732
Capital Cost ($)	$387,909,200	$285,207,400	$176,406,900	$56,328,065
Avg. Feedstock Cost at Plant ($/GJ)	$2.79	$2.98	$2.99	$3.00
Feedstock Costs ($/year)	$61,647,588	$42,786,113	$21,915,402	$4,430,510
Other O&M Cost ($/year)	$22,178,801	$16,068,205	$9,741,581	$3,001,959
Electricity Credit ($/year)	-$21,818,283	-$14,171,424	-$7,221,481	-$1,454,552
Compressed Gas Truck Terminal				
Capacity (kg/day)	-	234,645	119,570	24,084
Capital Cost ($)	-	$119,330,400	$73,468,783	$23,490,747
Electricity Costs ($/year)	-	$4,089,908	$2,084,137	$419,787
Other O&M ($/year)	-	$14,319,650	$8,816,254	$2,818,890
Liquid Truck Terminal				
Capacity (kg/day)	361,258	-	-	-
Capital Cost ($)	$427,859,200	-	-	-
Electricity Costs ($/year)	$81,077,669	-	-	-
Other O&M ($/year)	$17,114,369	-	-	-
Pipeline Terminal				
Capacity (kg/day)	-	-	-	-
Capital Cost ($)	-	-	-	-
Electricity Costs ($/year)	-	-	-	-
Other O&M ($/year)	-	-	-	-
Comp. Gas Truck Distribution				
Number of Trucks	-	160	82	17
Capital Cost ($)	-	$161,876,600	$82,505,845	$16,611,498
Fuel Costs ($/year)	-	$11,419,729	$2,846,575	$415,679
Other O&M ($/year)	-	$41,072,375	$19,222,066	$3,781,021
Liquid Truck Distribution				
Number of Trucks	30	-	-	-
Capital Cost ($)	$16,727,675	-	-	-
Fuel Costs ($/year)	$2,219,030	-	-	-
Other O&M ($/year)	$8,642,584	-	-	-
Pipeline Distribution				
Length of Pipeline (km)	-	-	-	-
Capital Cost ($)	-	-	-	-
O&M ($/year)	-	-	-	-
Refueling Stations (500 kg/day)				
Number of Comp. Gas Truck Stations	-	325	166	33
Number of Liquid Truck Stations	462	-	-	-
Number Pipeline Stations	-	-	-	-
Capital Cost ($)	$276,277,799	$175,801,999	$89,592,664	$18,042,730
Electricity Costs ($/year)	$2,503,423	$6,655,925	$3,391,729	$683,161
Other O&M Costs ($/year)	$27,139,477	$24,577,912	$12,526,743	$2,522,185
Total Delivered Hydrogen	84,290,408	59,353,729	30,245,502	6,092,055
Vehicles Served	386,299	272,015	138,614	27,920
Total Capital Cost	$1,108,773,871	$742,216,396	$421,974,189	$114,473,037
Capital Cost per Vehicle Served	$2,870	$2,729	$3,044	$4,100
Levelized Cost of Delivered H_2	$3.95	$4.09	$4.22	$5.14

Table 36: Summary of Results for Base Case 25% Demand Scenarios

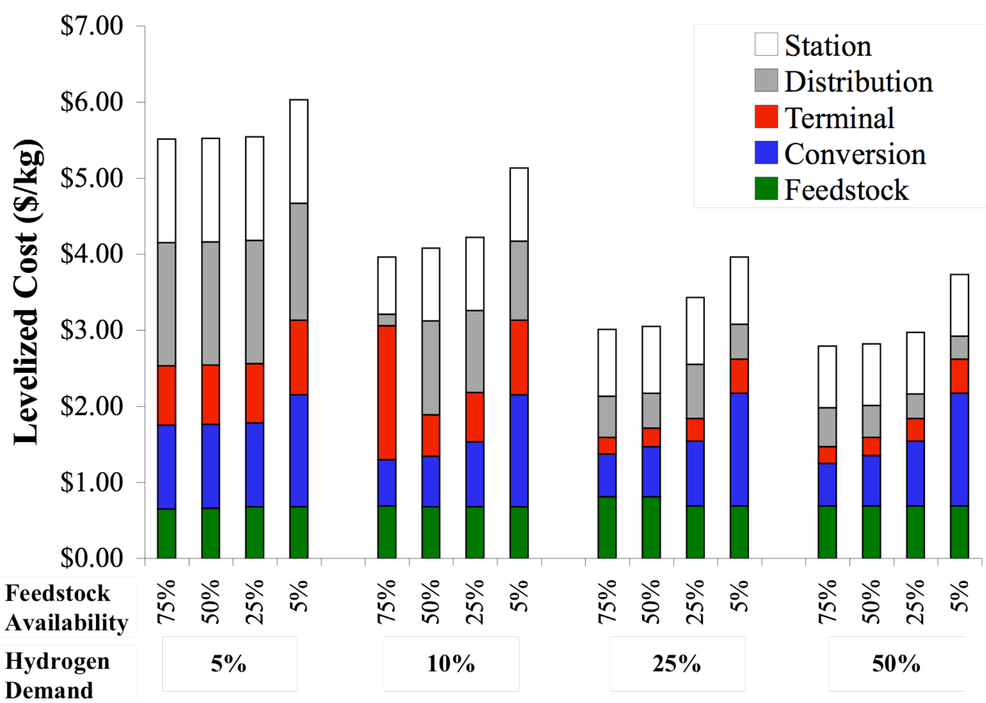
Hydrogen Demand (% of LDV)	**25%**	**25%**	**25%**	**25%**
Feedstock Availability	**75%**	**50%**	**25%**	**5%**
Economics	**base**	**base**	**base**	**base**
Facility Location	***Richmond***	***Richmond***	***Sacramento***	***Sacramento***
Gasification Plant				
Capacity (kg/day)	278,998	186,433	93,660	18,732
Capital Cost ($)	$385,957,700	$289,573,100	$177,298,600	$56,328,065
Avg. Feedstock Cost at Plant ($/GJ)	$3.53	$3.53	$3.00	$3.00
Feedstock Costs ($/year)	$77,470,698	$51,812,996	$22,152,550	$4,430,510
Other O&M Cost ($/year)	$22,061,601	$16,325,441	$9,792,708	$3,001,959
Electricity Credit ($/year)	-$21,664,444	-$14,476,740	-$7,272,761	-$1,454,552
Compressed Gas Truck Terminal				
Capacity (kg/day)	-	-	-	-
Capital Cost ($)	-	-	-	-
Electricity Costs ($/year)	-	-	-	-
Other O&M ($/year)	-	-	-	-
Liquid Truck Terminal				
Capacity (kg/day)	-	-	-	-
Capital Cost ($)	-	-	-	-
Electricity Costs ($/year)	-	-	-	-
Other O&M ($/year)	-	-	-	-
Pipeline Terminal				
Capacity (kg/day)	358,711	239,700	120,419	24,084
Capital Cost ($)	$70,067,152	$52,735,379	$32,503,311	$10,549,132
Electricity Costs ($/year)	$4,701,682	$3,141,785	$1,578,356	$315,671
Other O&M ($/year)	$7,540,156	$5,729,346	$3,586,609	$1,203,007
Comp. Gas Truck Distribution				
Number of Trucks	-	-	-	-
Capital Cost ($)	-	-	-	-
Fuel Costs ($/year)	-	-	-	-
Other O&M ($/year)	-	-	-	-
Liquid Truck Distribution				
Number of Trucks	-	-	-	-
Capital Cost ($)	-	-	-	-
Fuel Costs ($/year)	-	-	-	-
Other O&M ($/year)	-	-	-	-
Pipeline Distribution				
Length of Pipeline (km)	797	547	313	75
Capital Cost ($)	$451,548,000	$307,002,700	$177,597,200	$40,199,113
O&M ($/year)	$27,308,213	$22,460,782	$9,382,691	$4,385,773
Refueling Stations (1,000 kg/day)				
Number of Comp. Gas Truck Stations	-	-	-	-
Number of Liquid Truck Stations	-	-	-	-
Number Pipeline Stations	247	165	83	17
Capital Cost ($)	$274,636,398	$183,519,098	$92,195,533	$18,439,105
Electricity Costs ($/year)	$17,436,782	$11,651,707	$5,853,532	$1,170,705
Other O&M Costs ($/year)	$23,278,416	$15,555,238	$7,814,571	$1,562,913
Total Delivered Hydrogen	90,280,544	60,327,788	30,307,209	6,061,442
Vehicles Served	413,751	276,479	138,896	27,779
Total Capital Cost	$730,661,246	$525,827,573	$301,997,440	$85,316,298
Capital Cost per Vehicle Served	$1,766	$1,902	$2,174	$3,071
Levelized Cost of Delivered H_2	$3.27	$3.40	$3.64	$4.55

Table 37: Summary of Results for Base Case 50% Demand Scenarios

Hydrogen Demand (% of LDV)	**50%**	**50%**	**50%**	**50%**
Feedstock Availability	**75%**	**50%**	**25%**	**5%**
Economics	**base**	**base**	**base**	**base**
Facility Location	***Sacramento***	***Sacramento***	***Sacramento***	***Sacramento***
Gasification Plant				
Capacity (kg/day)	278,998	186,433	93,660	18,732
Capital Cost ($)	$385,957,700	$289,573,100	$177,298,600	$56,328,065
Avg. Feedstock Cost at Plant ($/GJ)	$2.99	$3.00	$3.00	$3.00
Feedstock Costs ($/year)	$65,746,205	$43,978,387	$22,152,550	$4,430,510
Other O&M Cost ($/year)	$22,061,601	$16,325,441	$9,792,708	$3,001,959
Electricity Credit ($/year)	-$21,664,444	-$14,476,740	-$7,272,761	-$1,454,552
Compressed Gas Truck Terminal				
Capacity (kg/day)	-	-	-	-
Capital Cost ($)	-	-	-	-
Electricity Costs ($/year)	-	-	-	-
Other O&M ($/year)	-	-	-	-
Liquid Truck Terminal				
Capacity (kg/day)	-	-	-	-
Capital Cost ($)	-	-	-	-
Electricity Costs ($/year)	-	-	-	-
Other O&M ($/year)	-	-	-	-
Pipeline Terminal				
Capacity (kg/day)	358,711	239,700	120,419	24,084
Capital Cost ($)	$70,067,152	$52,735,379	$32,503,311	$10,549,132
Electricity Costs ($/year)	$4,701,682	$3,141,785	$1,578,356	$315,671
Other O&M ($/year)	$7,540,156	$5,729,346	$3,586,609	$1,203,007
Comp. Gas Truck Distribution				
Number of Trucks	-	-	-	-
Capital Cost ($)	-	-	-	-
Fuel Costs ($/year)	-	-	-	-
Other O&M ($/year)	-	-	-	-
Liquid Truck Distribution				
Number of Trucks	-	-	-	-
Capital Cost ($)	-	-	-	-
Fuel Costs ($/year)	-	-	-	-
Other O&M ($/year)	-	-	-	-
Pipeline Distribution				
Length of Pipeline (km)	556	377	198	53
Capital Cost ($)	$317,525,600	$214,335,200	$110,911,100	$27,381,846
O&M ($/year)	$13,979,581	$11,516,297	$8,288,422	$3,903,381
Refueling Stations (1,500 kg/day)				
Number of Comp. Gas Truck Stations	-	-	-	-
Number of Liquid Truck Stations	-	-	-	-
Number Pipeline Stations	165	110	55	11
Capital Cost ($)	$259,055,398	$173,107,498	$86,964,997	$17,392,998
Electricity Costs ($/year)	$17,436,782	$11,651,707	$5,853,532	$1,170,705
Other O&M Costs ($/year)	$20,304,707	$13,568,128	$6,816,296	$1,363,258
Total Delivered Hydrogen	90,280,544	60,327,788	30,307,209	6,061,442
Vehicles Served	413,751	276,479	138,896	27,779
Total Capital Cost	$715,080,246	$515,415,973	$296,766,904	$84,270,191
Capital Cost per Vehicle Served	$1,728	$1,864	$2,137	$3,034
Levelized Cost of Delivered H_2	$2.85	$2.98	$3.23	$4.15

Chart 6 shows how each component contributes to the levelized cost of delivered hydrogen. The rice straw contributes between \$0.65 and \$0.81 per kilogram dependent mostly on the location of the facility. It is interesting to note the impact of fuel demand density on the delivered cost. The 10%, 25% and 50% demand scenarios use approximately the same fields for feedstock yet the increasing demand density and station sizes allow the 50% scenarios to cost more than a dollar less per kilogram than the 10% scenarios. Also of note is the difference between the delivery modes component importance. With liquid trucks (10% demand/75% rice straw) the terminal cost is by far the most important while the compressed gas truck and pipeline (25% and 50% demands) cost components are more evenly distributed.

Chart 6: Breakdown of Base Case Levelized Costs



Supply Curve Analysis

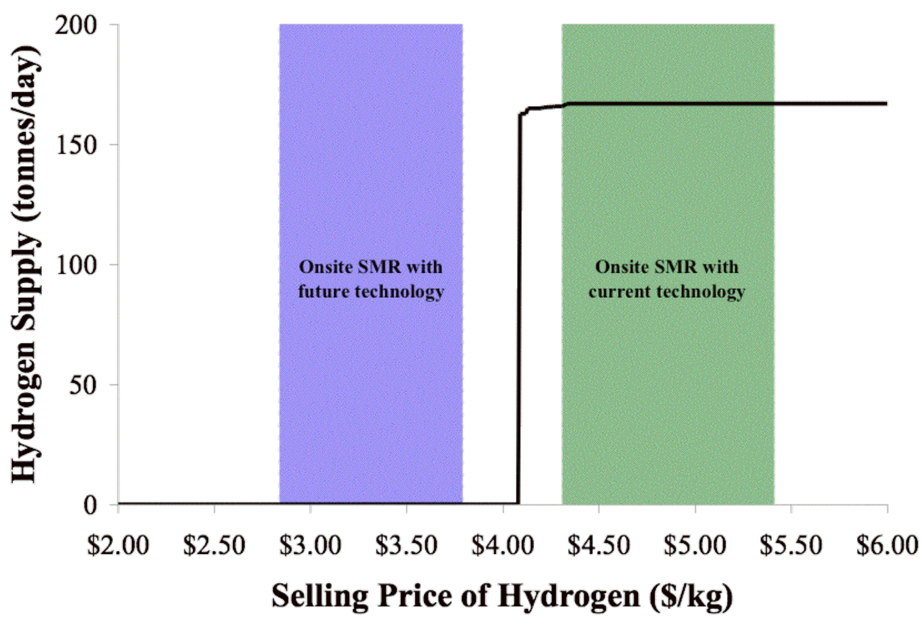
In systems where levelized costs eventually increase with scale, the level of hydrogen supply will be dependent on the selling price of hydrogen offered. Many of the systems analyzed here have rising marginal costs near the maximum supply due to the fields that are to the far north and south. The supply curves represent the quantity of hydrogen that would be produced from rice straw at given selling prices of the hydrogen for the given supply and demand distributions. The supply curves only represent a handful of optimal configurations, with configurations changing where the supply curve jumps. Where the supply curve is flat represents a profit-taking region for the hydrogen supplier maintaining the optimal configuration of the previous jump.

For reference, the cost ranges for on-site steam methane reformer-based stations of the same size as the stations in each demand scenario are included on the supply curve charts. Current and future technology costs are adapted from the National Academies report (NAS 2004). Cost ranges were calculated based on natural gas prices of $5.11 per mmBtu to $10.13 per mmBtu. These prices represent the 10th lowest and 10th highest monthly average commercial natural gas prices in California for the period January 2000 to November 2010 according to the Energy Information Administration (EIA 2007).

Two example supply curves are given below. Supply curves for the other systems that demonstrated variable hydrogen supply with price, more than one system optimal configuration, are given in Chart 11 through Chart 15 at the end of the chapter.

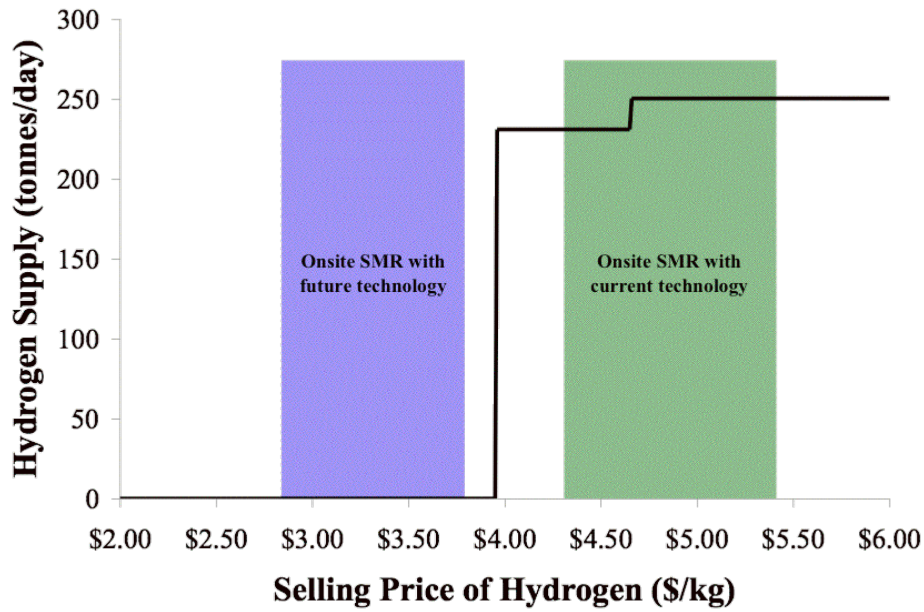
Most systems demonstrated a supply curve like the one shown in Chart 7 for the 10% demand/50% rice straw scenario. Thinking of the system as adding fields from the nearest to the farthest and calculating the cost, the system will reach a lowest cost point when the increased cost of the additional feedstock and hydrogen delivery is greater than the reduction in cost by economies of scale in the gasification facility and the hydrogen terminal. This point is where the supply curve jumps from zero to some quantity. From there on additional hydrogen supply will require a higher selling price greater than its marginal cost to be made available. In the case studies performed here, the economies of scale in the gasification unit and hydrogen terminals are very strong in the size range leading to the collection of most straw before the lowest cost system is reached. Larger supplies would needed to induce supply curves with wider ranges.

Chart 7: Supply Curve for 10% Demand/50% Straw Scenario



In Chart 8, the supply curve has only two optimal configurations. The first step uses liquid hydrogen delivery with a conversion facility that uses all of the available feedstock. Due to hydrogen losses in the liquid hydrogen delivery mode this system does not deliver the maximum possible quantity of hydrogen. At a significantly higher price, the marginal cost of a compressed gas truck-based system is met and the maximum quantity of hydrogen is produced.

Chart 8: Supply Curve for 10% Demand/75% Straw Scenario



Visual Display of Results

Due to the geographic nature of this work, results are sometimes easiest to understand through a visual display of the results. Maps showing the optimal system configuration can be developed using the model output, (facility location, rice fields used, demand clusters served, and delivery routes) and the GIS data layers where this data originated. Figure 17 and Figure 18 (at end of chapter) demonstrate this capability for the lowest cost system configurations for the 10% demand case with 50 and 75 percent rice straw availability respectively.

Sensitivity Analysis

Sensitivity Analysis Description

The rice straw to hydrogen supply chain considered here faces uncertainty in many important parameters. These parameters can be classified into two categories. The first category contains parameters that are unknown due to lack of experience with the technologies considered but whose uncertainty would be greatly reduced at the time of decisions by industry to build the infrastructure. These parameters include gasifier capital cost, scaling factor, and efficiency as well as the costs of straw harvest and building hydrogen pipelines in urban areas. Sensitivity analysis is required for these variables in order to span the space of potential outcomes from the engineering learning process. The second category includes parameters that will not be well known at the time of supply chain design including input prices, capacity factors, and the levels of straw supply and hydrogen demand. These parameters require a sensitivity analysis for the more traditional reason of informed design.

Sensitivity analysis was performed through scenario analysis on parameters that are expected to have significant effect on not only the cost of delivered hydrogen but also the design of the system. The parameters were varied and the system was optimized to the new parameters. The capital costs of both the gasification facility and the hydrogen pipelines were analyzed. These two capital costs were singled out due to their uncertainty and effect on the system. The rice straw harvest costs were reported with a great deal of variability by Jenkins *et al* (2000); sensitivity is performed at the bounds of their reported values. The efficiency of the gasification facility is also varied within the range of reported values in the literature.

The strength of economies of scale in the gasification facility has a large impact on the design of the system. To analyze the effect of the scaling factor on the system design while minimizing the impact on the total system cost, I altered the gasification capital cost function by keeping the cost the same at a base facility size of 100,000 kilogram per day of hydrogen production and varying the scaling factors.

The basic economic parameters of input prices, the rate of return, and the capacity factor were subjected to sensitivity analysis through scenario analysis. The parameters were varied and the system was optimized to the new parameters. This type of analysis tests the robustness of the optimal solution under the likely range of uncertainty. The values of the lower bound, base case, and upper bound of sensitivity parameters are given in Table 38.

Table 38: Sensitivity Analysis Parameter Values

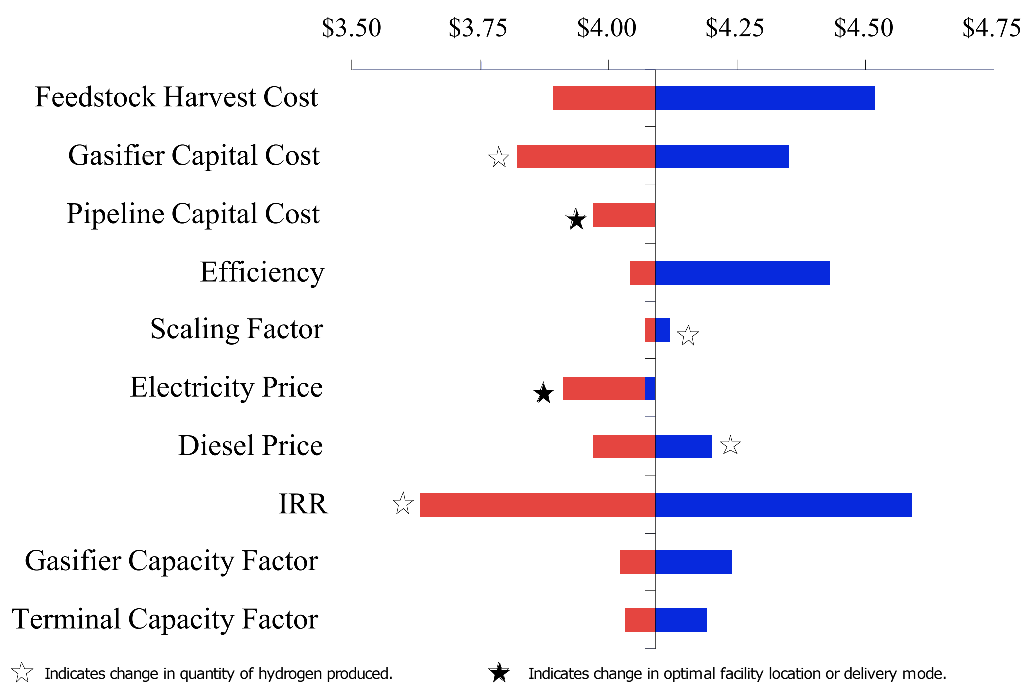
Parameter	High Value	Base case	Low Value
Feedstock Harvest Cost	+90%	See above	-40%
Gasifier Capital Cost	+30%	$185 million for 100,000 kg/day	-30%
Pipeline Capital Cost ($/mile)	$1,230,680 $1,846,020	$615,340 $923,010	$461,505 $692,258
Gasifier Efficiency	65%	63%	51%
Gasifier Scaling Factor	0.80	0.72	0.68
Electricity Price	$0.11/kWh	$0.09/kWh	$0.055/kWh
Diesel Price	$3.50/gal	$2.50/gal	$1.50/gal
IRR	15%	10%	5%
Gasifier Capacity Factor	0.95	0.9	0.8
Terminal Capacity Factor	0.5	0.7	0.9

Sensitivity analysis is performed on the 10% and 25% hydrogen demand scenarios with 50% rice straw availability. These two scenarios were chosen because they represent the gaseous truck delivery and pipeline delivery paradigms respectively. They are also closer to breakpoints where the delivery mode is switched than the 5% and 50% demand scenarios.

Sensitivity Results

A tornado plot of the sensitivity results for the 10% demand scenario is given in Chart 9. The tornado chart depicts the variation from the base case Levelized cost (denoted by the center line) for each uncertain parameter. The parameter value resulting in a lower value is shown in red with the larger value in blue. This analysis compares the lowest cost system configuration for each value of the parameters which in some cases results in different hydrogen quantities delivered and by different modes. The white stars denote a significant change in the optimal quantity of straw consumed by the system. Black stars point out where the system configuration is altered in facility location and/or hydrogen delivery mode.

Chart 9: Tornado Plot for 10% Demand Sensitivity Analysis

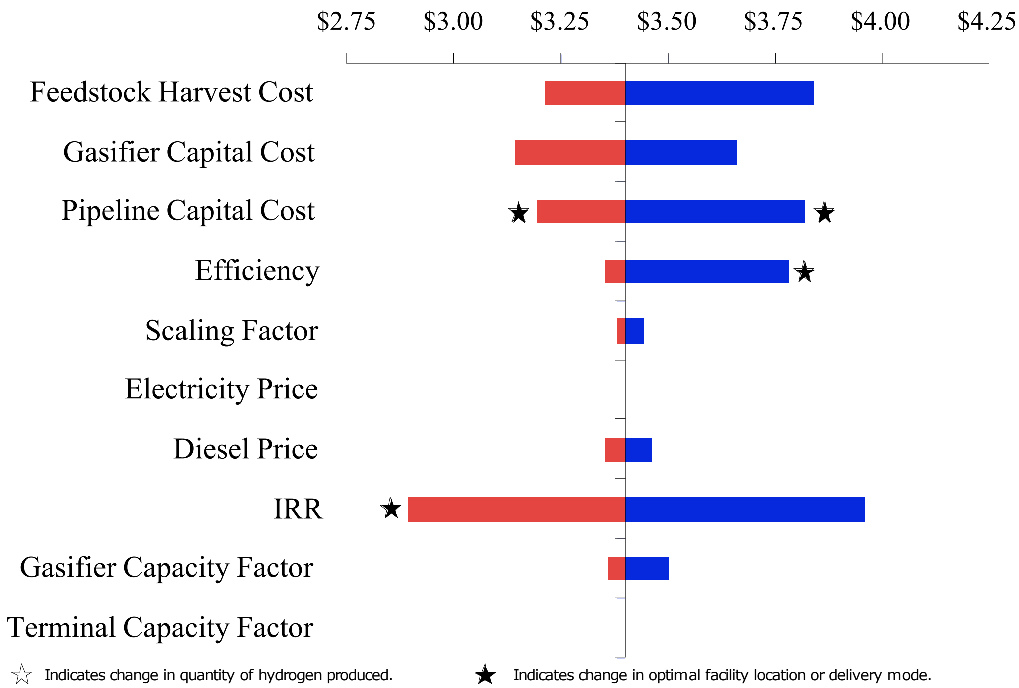


One result that is immediate is the capital intensity of the system, having the most variation in cost due to the internal rate of return. Lower pipeline capital cost leads to a switch in the system configuration to a pipeline facility in Richmond. Decreasing the electricity costs leads to facility at the Field Site delivering hydrogen by liquid tanker trucks.

Reducing the electricity price changes the optimal configuration to using the electricity intensive liquid delivery mode. Electricity price is one of the parameters that will not be known at the time of infrastructure design. The regret of choosing the wrong strategy can be calculated to help determine which strategy is best. If the liquid hydrogen delivery configuration is chosen to supply a hydrogen demand with a selling price of $4.25 per kilogram and the electricity price turns out to be high ($0.11/kWh), the industry loses $6 million per year compared to making $10.6 million per year with the optimal design at that price. In the other direction, with a low electricity price and gaseous truck delivery serving the same $4.25 per kilogram hydrogen demand, the industry makes only $8.6 million per year compared to making $19.1 million with the liquid delivery configuration. Comparing these two regrets, the best choice for the industry is to build the configuration with gaseous truck delivery as it has the lowest regret when not optimal and more importantly is profitable under all scenarios.

The 25% demand case has results similar to the 10% demand case for most sensitivity parameters. Reducing the internal rate of return has an interesting impact on the system design. By reducing the size of the capital cost paid per kilogram, the feedstock cost plays a larger role in determining the location of the facility leading to moving the facility from Richmond to Sacramento when the internal rate of return is reduced. Reducing the pipeline capital cost had the same effect. Increasing pipeline costs leads to a switch to compressed gas truck delivery of hydrogen and relocating the facility to Sacramento. Decreasing the efficiency of the gasifier caused the facility to be relocated to Sacramento where it serves a smaller demand than the Richmond site.

Chart 10: Tornado Plot for 25% Demand Sensitivity Analysis



There are a few parameters that will have large uncertainties at the time of supply chain design that have proven to be important in the design of the facility. The two most important factors are hydrogen demand and feedstock supply, though they were not embodied as sensitivities here but as separate scenarios above. The cost of hydrogen pipelines has a major impact on supply chain design and is highly uncertain even at the design phase. The price of electricity is especially important for the viability of liquid hydrogen delivery. While the desired internal rate of return on capital has a major impact on the cost of producing hydrogen, it is not likely to be uncertain at the time of design by industry.

Figure 11: Census Population Data

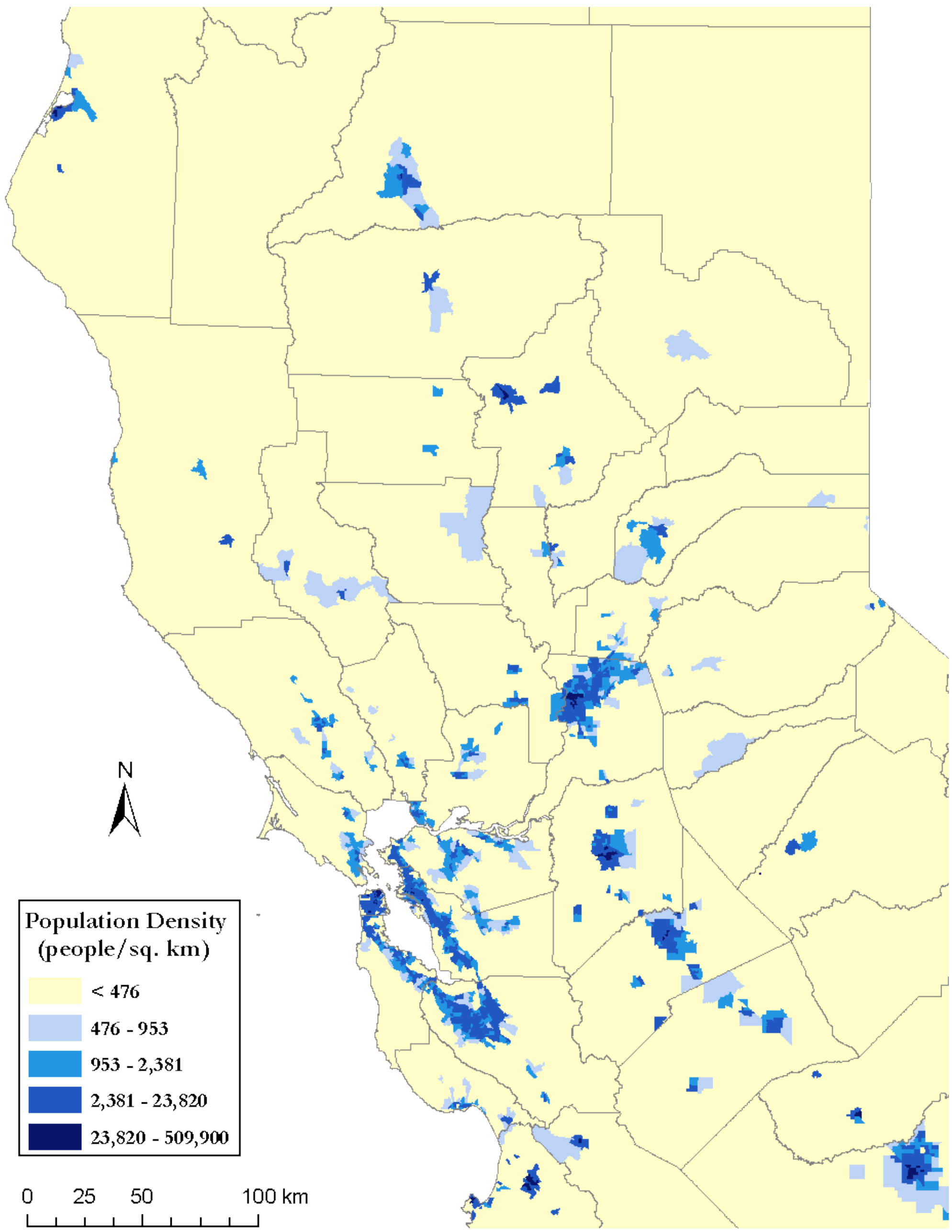


Figure 12: Hydrogen Demand Densities for 1% Demand Scenario

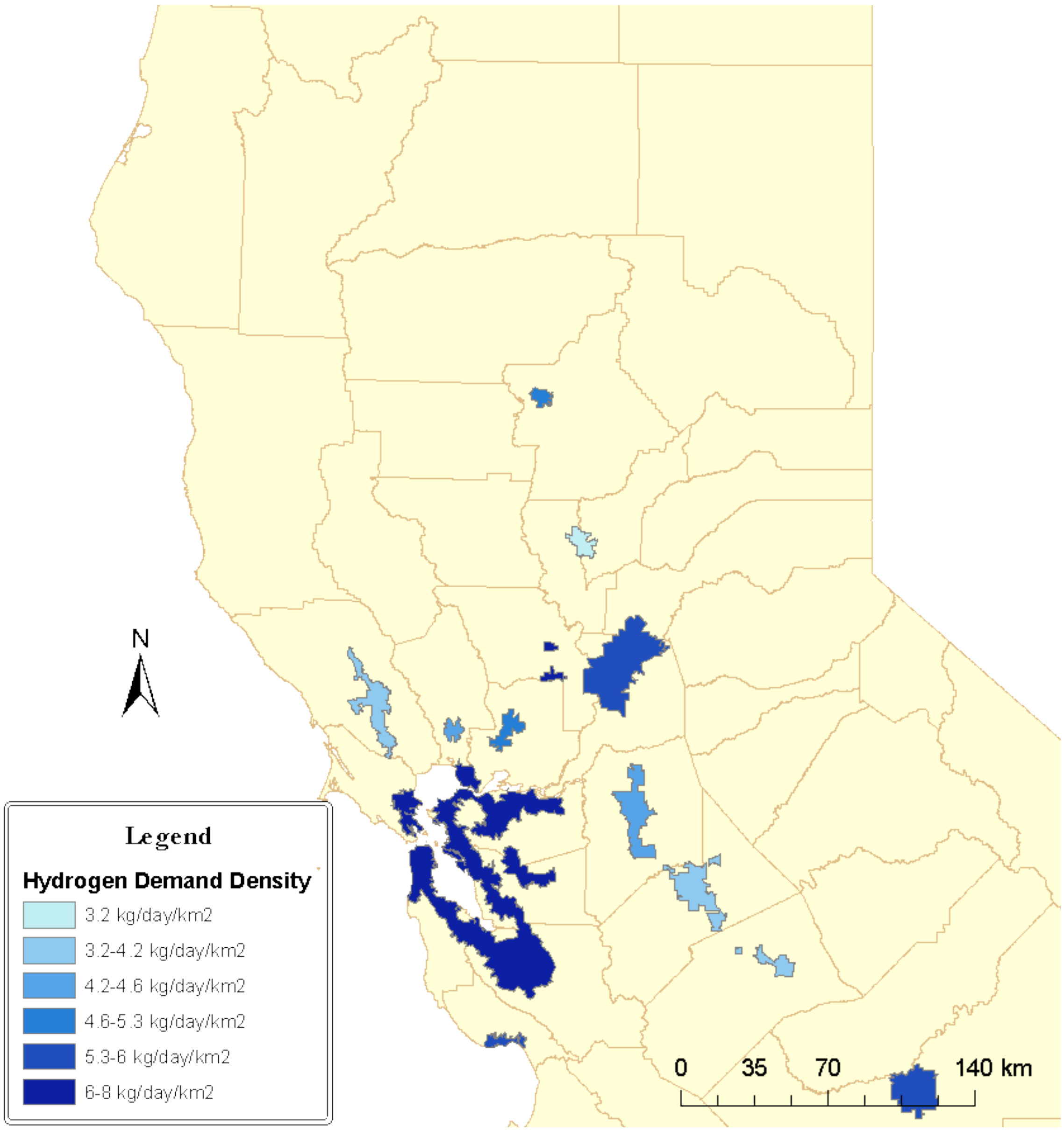


Figure 13: Hydrogen Demand Densities for 10% Demand Scenario

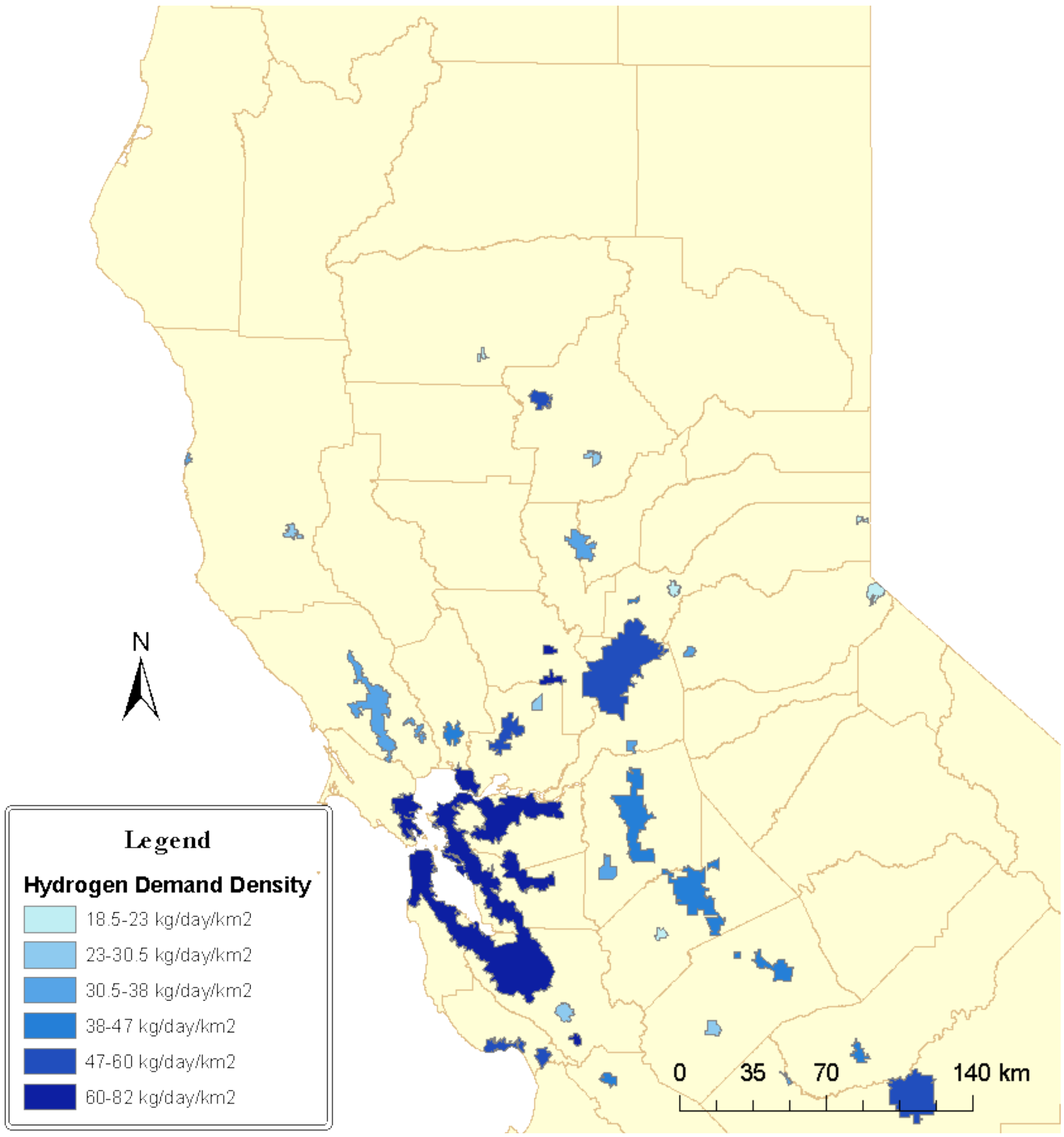


Figure 14: Hydrogen Demand Densities for 25% Demand Scenario

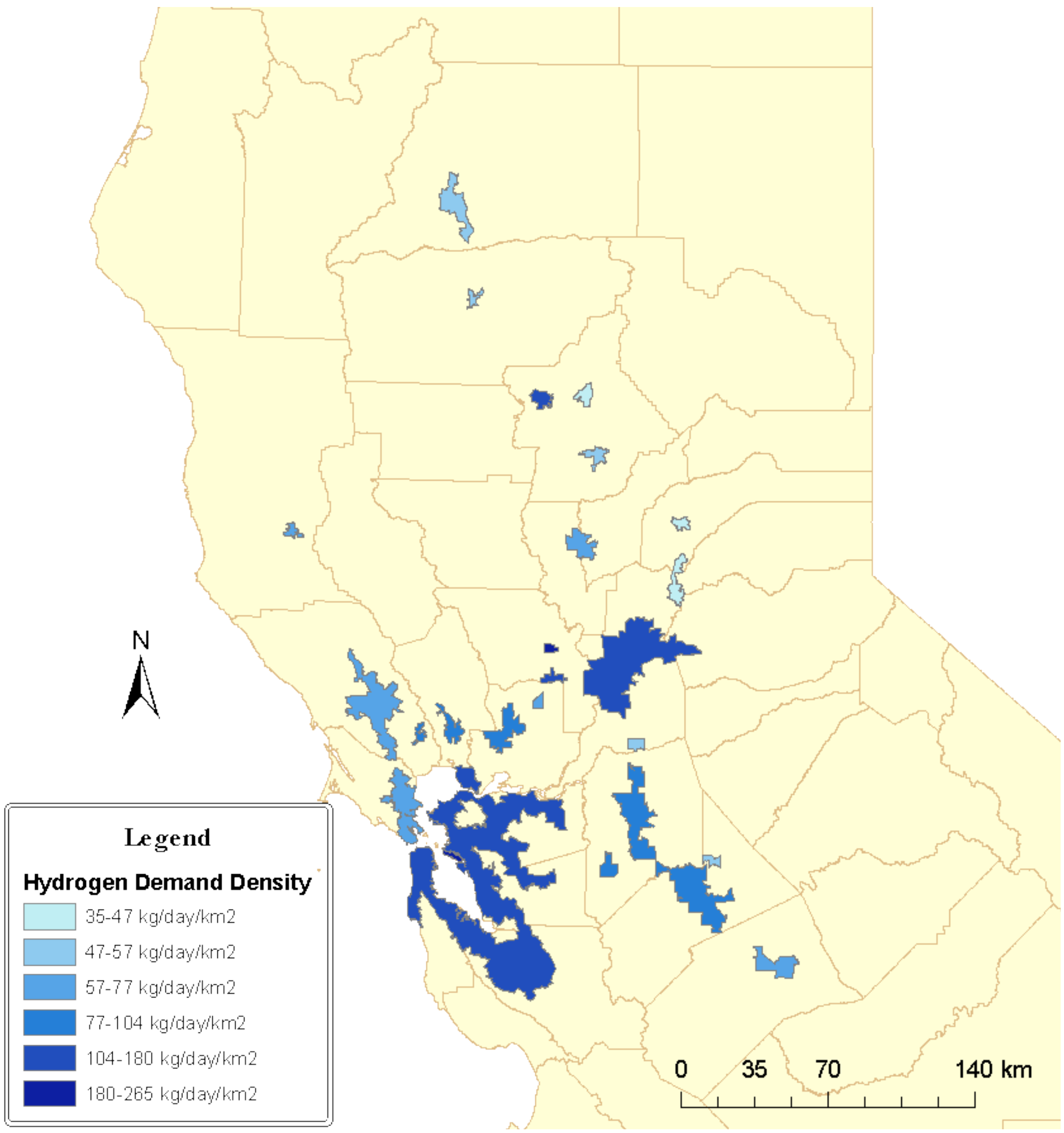


Figure 15: Hydrogen Demand Densities for 50% Demand Scenario

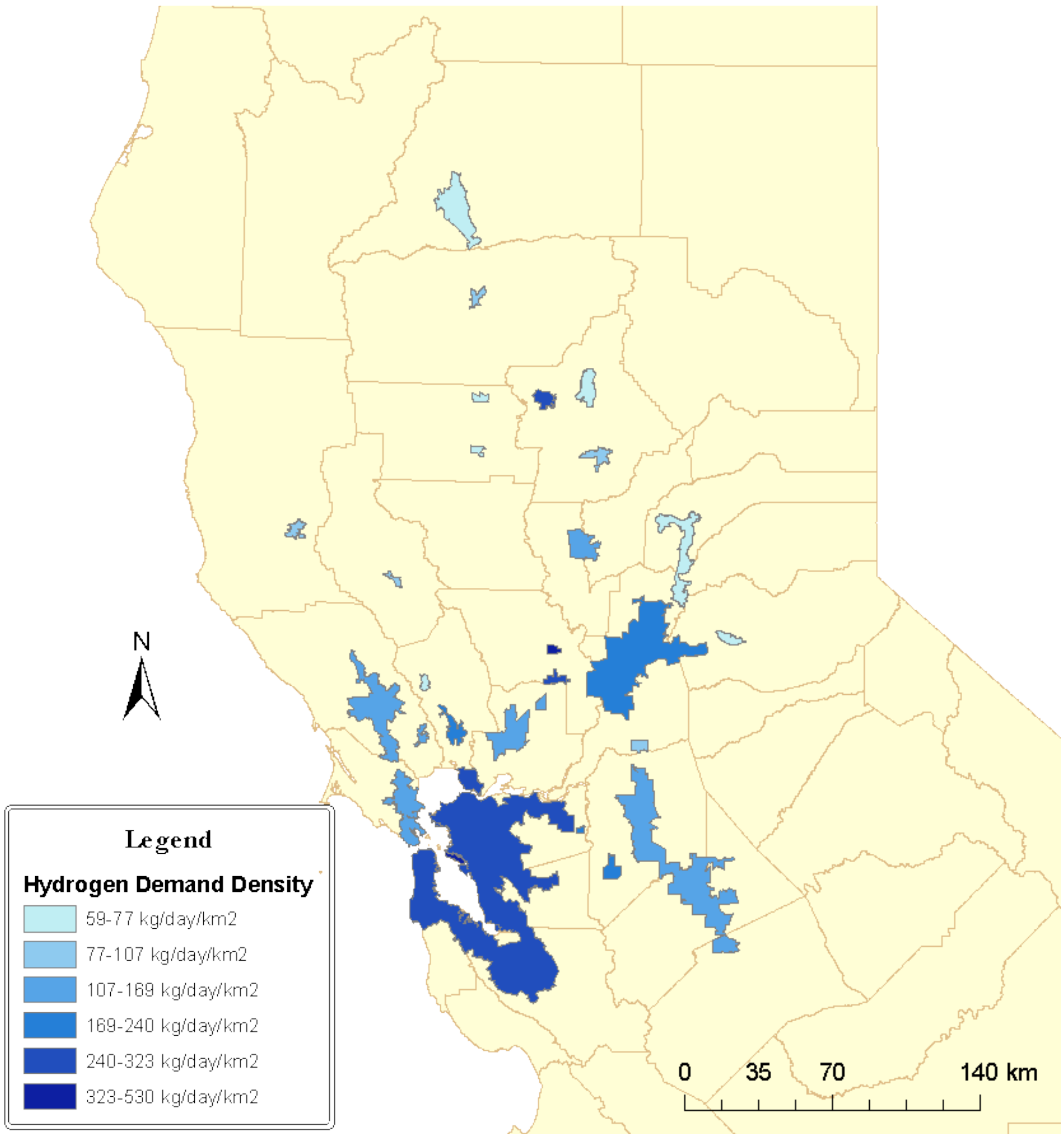


Figure 16: Field Clustering Graphic

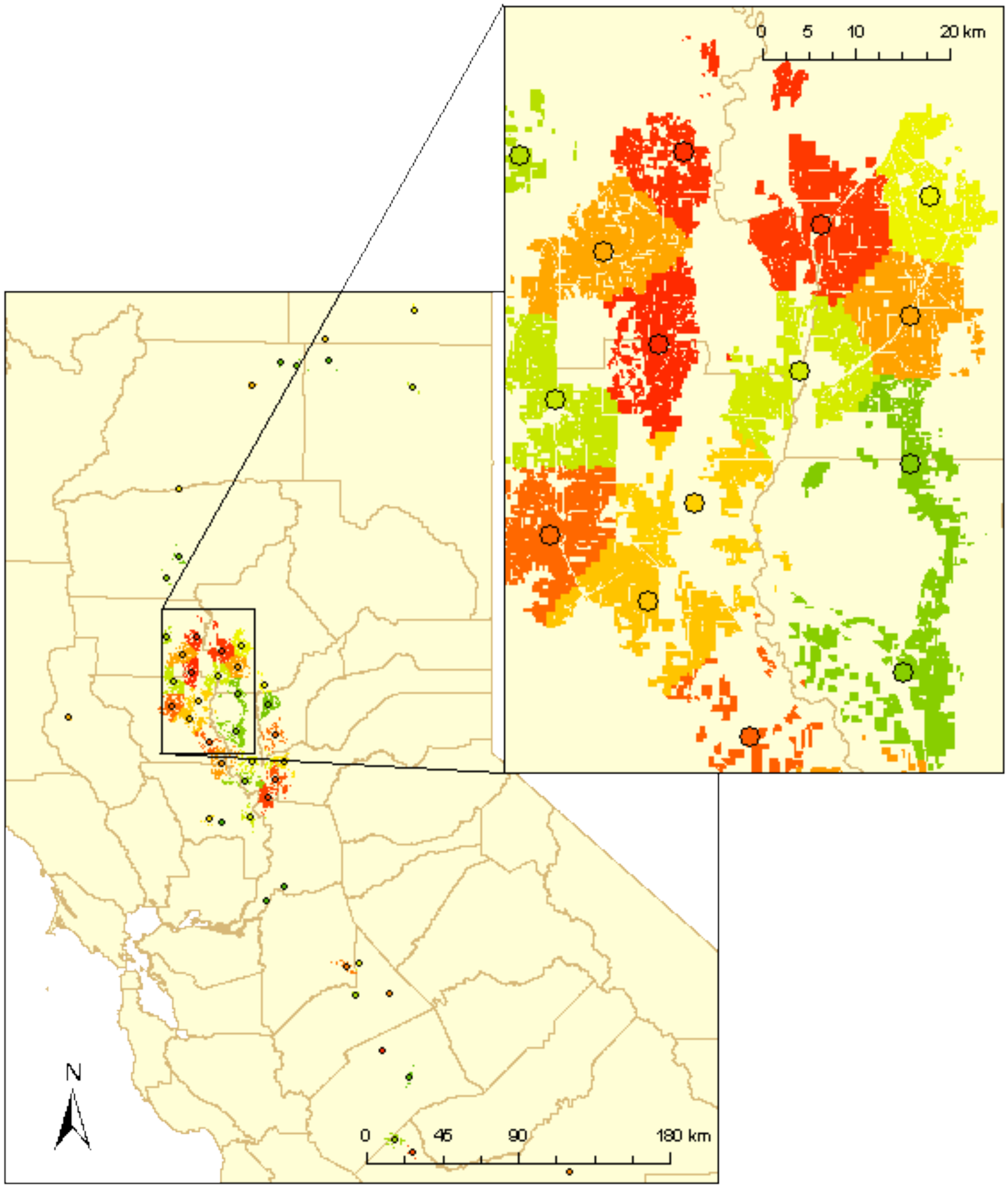


Chart 11: Supply Curve for 10% Demand/25% Straw Scenario

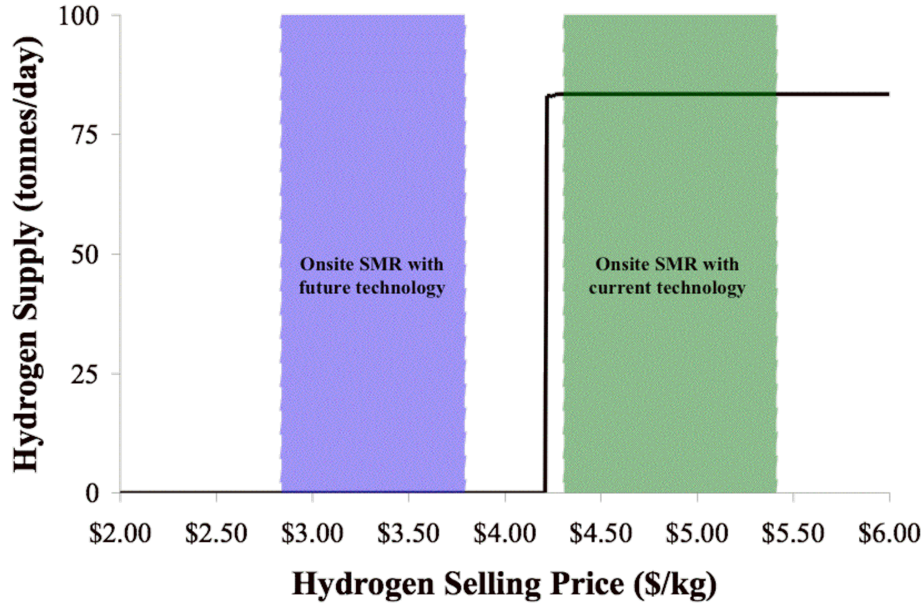


Chart 12: Supply Curve for 25% Demand/50% Straw Scenario

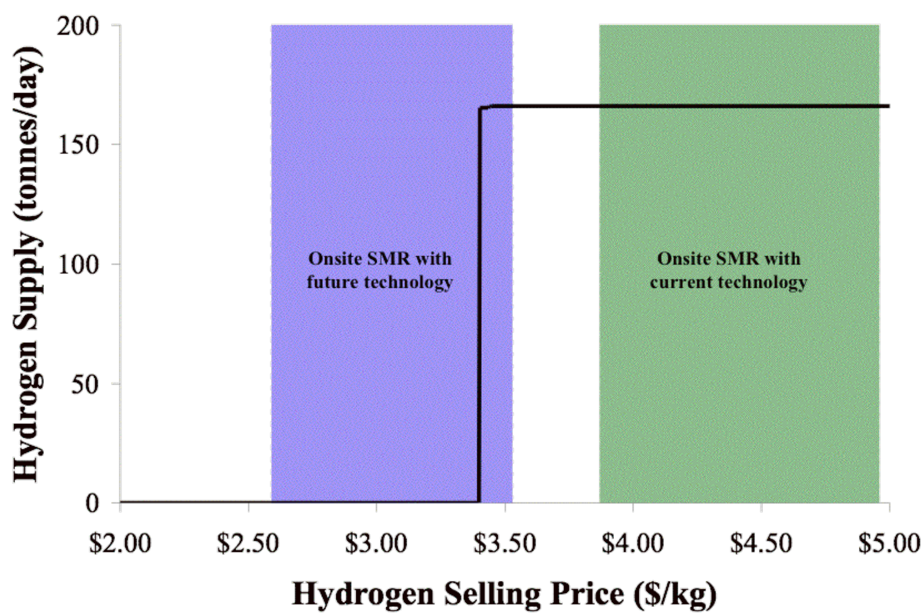


Chart 13: Supply Curve for 25% Demand/75% Straw Scenario

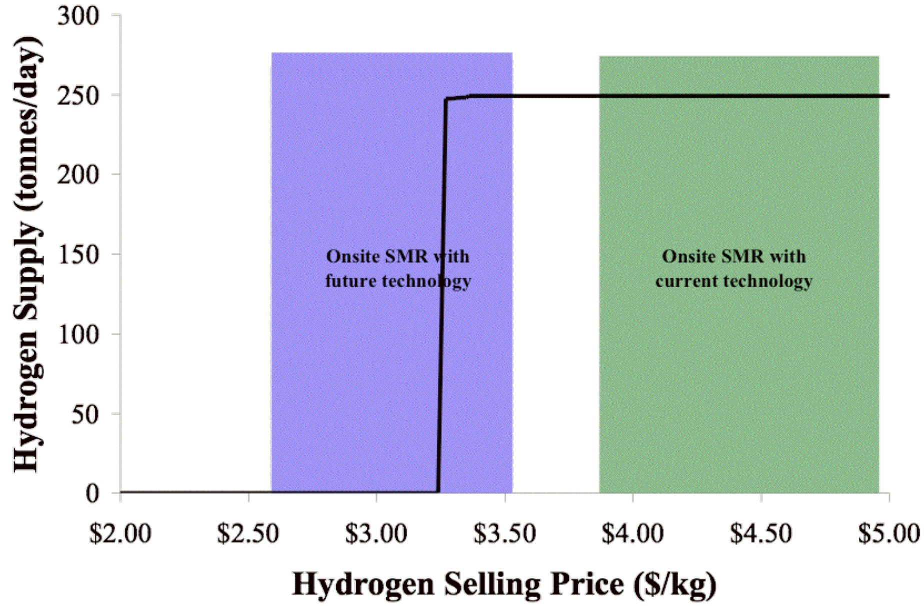


Chart 14: Supply Curve for 50% Demand/50% Straw Scenario

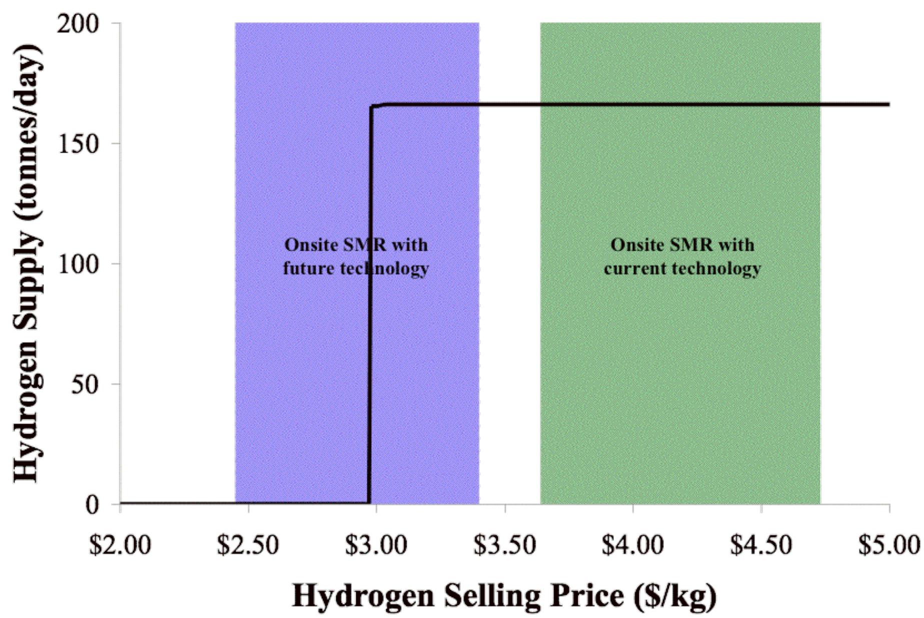


Chart 15: Supply Curve for 50% Demand/75% Straw Scenario

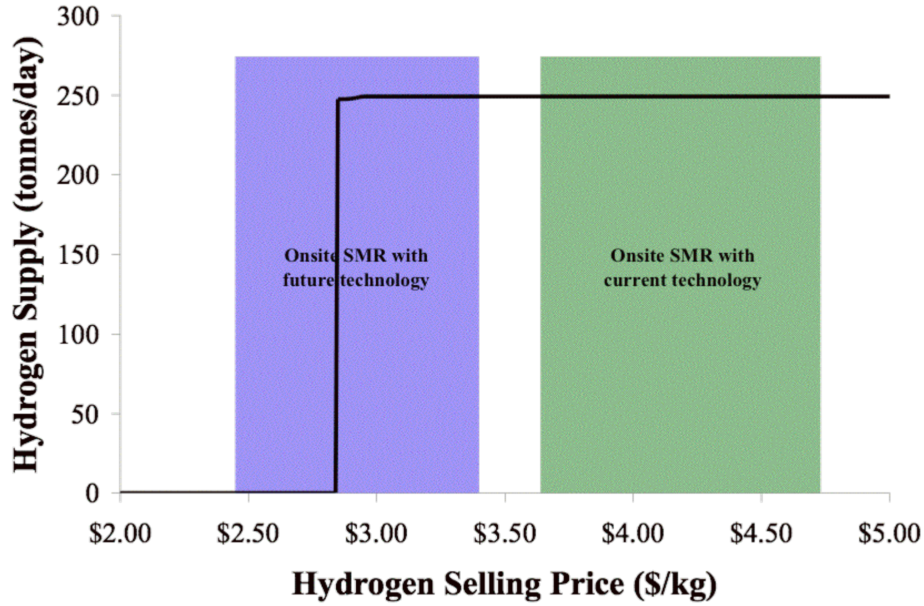


Figure 17: Optimal System Configuration for 10% Demand/50% Rice Straw Scenario

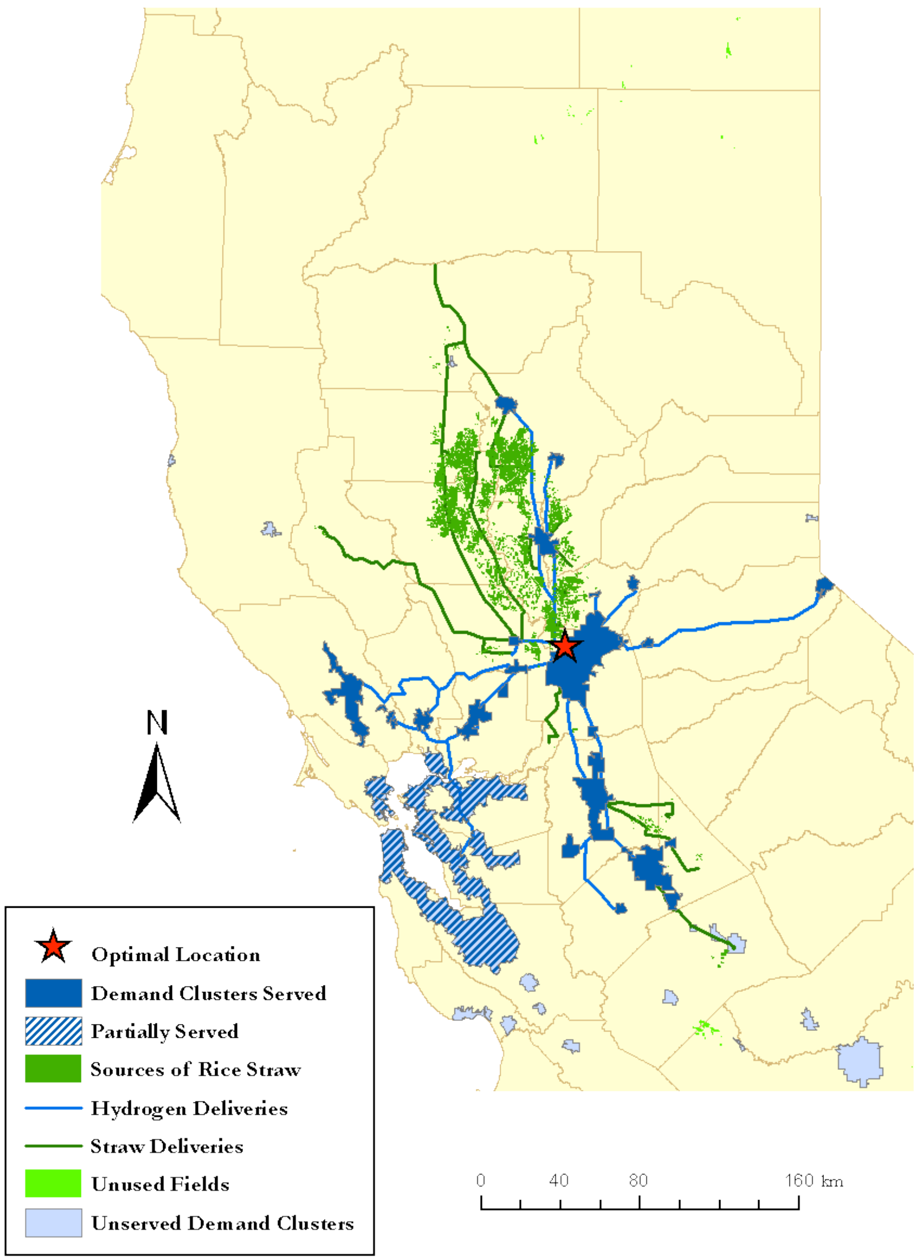
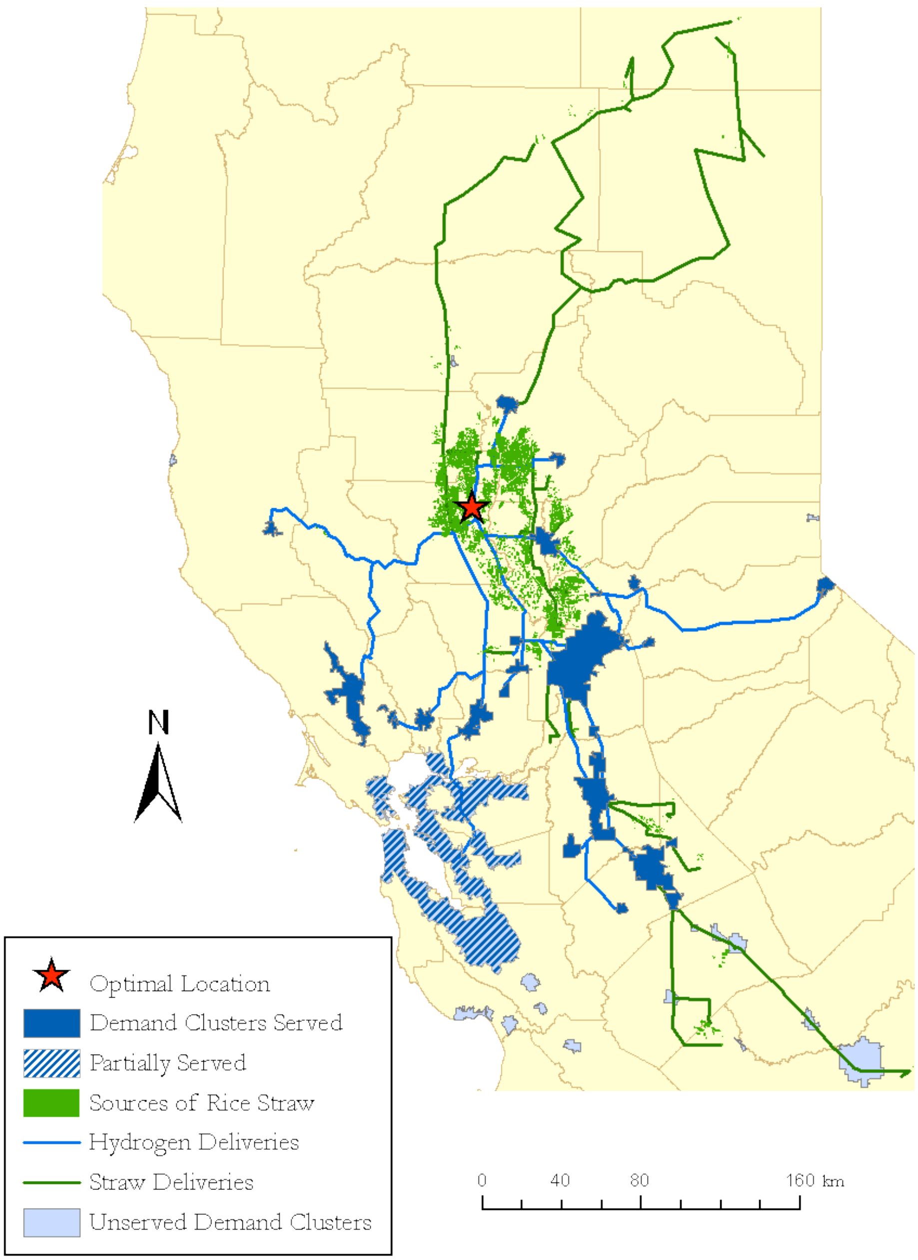


Figure 18: Optimal Configuration for 10% Demand/75% Rice Straw Scenario



Conclusion

Implications for Policy

This work was an exploration of the potential of biomass as a low-carbon source of hydrogen through optimization of the full supply chain. "Conventional wisdom", for example the National Academies study (NAS 2004), suggests that biomass would not be competitive with onsite steam methane reformers (SMR) in the near to mid-term time frame. The National Academies study projected that onsite SMR would be the dominant early to midterm technology for hydrogen production. The analysis presented here leads to a different conclusion.

I have demonstrated that the hydrogen from biomass can be competitive with what has traditionally been considered a near term strategy of onsite steam methane reformation. The results of this thesis show that in the case examined, hydrogen from biomass could be competitive with the projected costs of the distributed production of hydrogen by steam methane reformation. All cases fell below or within the range of costs for onsite SMR with current technology. Cases with high demand density (25% and 50%) that can take advantage of lower cost hydrogen delivery are competitive with the future technology case of onsite SMR.

There are several reasons why this analysis provides a more optimistic assessment of biomass-based hydrogen than the National Academies. Better technical and economic data for biomass gasifiers that come from an extensive literature review are used here. Economies of scale play a large role in making biomass hydrogen competitive. The National Academies study looked at only 24 tonnes per day of hydrogen capacity, which is a very small scale biomass facility. The economies of scale occur in several places, in the gasification plant, in the hydrogen terminal, and sometimes in the pipeline network. The work presented here is gives a more reliable estimate of cost due to explicitly accounting for the trade-offs between economies of scale and feedstock/hydrogen delivery costs in the biomass/hydrogen system. The result is that larger biomass facilities are preferred despite a higher feedstock cost resulting in lower delivered hydrogen costs.

Biomass hydrogen, however, should be considered as a part of the hydrogen supply chain. It is not a "silver bullet" solution to alternative fuel needs. First of all, there is not enough waste biomass, as shown in the Introduction, or land to grow energy crops to supply a full fleet of hydrogen vehicles. Secondly, though competitive to onsite SMR in many cases, biomass hydrogen is likely to be significantly more costly than centralized coal or natural gas based hydrogen facilities. These fossil sources are likely to be used to improve the economics of hydrogen supply while biomass could provide an improvement in environmental quality of the fuel with a marginal price increase.

This work demonstrates that biomass may be the lowest cost source of renewable, low-carbon hydrogen under certain conditions, which has a number of policy implications. First, it deserves a high priority in the hydrogen research funding budget on the federal level. Second, policy makers should work to improve the regulatory environment for the construction of biomass-based facilities along with their work on hydrogen codes and standards if they are to take advantage of biomass as a source of hydrogen. In at least California and likely in other states, bioenergy facilities face a number of regulatory hurdles that need to be streamlined to encourage the use of biomass for energy production (CEC 2006). Third, biomass hydrogen should be expressly considered in the development of a regulatory framework to take advantage of hydrogen's potential as an environmentally-friendly fuel.

Limitations of the Model

The inherent limitations of the work I presented here are discussed in this section. The uncertainty in important parameters, such as hydrogen demand, feedstock supply, cost of pipeline construction, electricity price, and the selling price of hydrogen, lead to a variety of optimal solutions depending on the assumed values for each parameter. Solutions are not inherently robust as can be seen in the example of electricity price in the 10% demand sensitivity analysis. Optimizing based on a low price gave high rewards in term of large profit but also proved to be risky if the electricity price went high leading to industry losses. However, optimizing based on high electricity price ensured profits throughout the range of electricity prices but the profits were modest in the event of low electricity prices. Developing scenario analysis around trade-offs, like this, could be a good method for gaining knowledge about the system. However, it is likely that interaction effects between the uncertain parameters will make it necessary to use stochastic modeling techniques to find truly robust solutions.

Temporal dynamics were not included in this analysis due to the added complexity that they present. Accounting for dynamic growth in hydrogen demand will likely lead to a different solution than those found here. For example, a hydrogen pipeline network is less likely to be chosen in cases where the demand is shifting; the more flexible truck delivery options would be favored.

The scaling factor for the biomass gasification facility is variable with the plant size (Hamelinck *et al.* 2002; Lau *et al.* 2003; Larson *et al.* 2005). Not accounting for this variability will lead to over sizing the "optimal" facility as pointed out by Jenkins (1997). For the facility considered here, the gasifier units reach their maximum size at 165 tonnes of hydrogen per day and two half-sized gasifiers are operated in parallel beyond that size. This point is where the scaling factor becomes variable. It is likely that many of the optimal facilities found here are larger than they would be with a more detailed cost function for the gasification facility.

One other note on scaling factors, the reported values for hydrogen compressor cost had a wide range of scaling factors (0.667 – 0.9). The low value, which came from H2A (DOE 2006), is used here. This is likely to have a major impact on system design as the higher scaling factor will lead to more favorable evaluations of multiple facility solutions, especially for the compressed gas truck delivery mode.

Lessons Learned

Optimal System Design

Optimization can improve the economics of systems producing hydrogen from biomass and optimal systems differ with different inputs. The optimal hydrogen delivery mode choice while needing to be made jointly with the location and facility size appears to be the main factor in system design. If a facility size and hydrogen demand distribution favors pipelines or compressed gas trucks, the facility is located to minimize hydrogen delivery costs. To the contrary, if liquid hydrogen delivery is favored, the facility is located to minimize the feedstock costs. This is due to the fact that the marginal cost of an additional mile of rice straw transport is less than that of compressed hydrogen trucks and most flow rates of hydrogen pipelines on an hydrogen energy basis. The opposite is true for liquid hydrogen delivery and for high throughput hydrogen pipelines.

The economies of scale of the hydrogen terminals combine with the economies of scale of the gasifier to rule out small facilities serving small local demands. Under no conditions in the models presented here or in previous versions with different cost functions did a facility significantly smaller than the resource base emerge as part of an optimal solution. The low scaling factors for the liquefier and compressors (0.523 and 0.667) have as much influence on this result as the scaling factor of the gasifier.

Optimal systems are highly dependent on the cost equations used. In developing the present model, three iterations of cost functions were used. In one, not presented here, where hydrogen losses due to boil-off were not accounted for, liquid hydrogen was the dominant delivery mode choice. In other model iterations, pipeline delivery was rarely chosen due to high assumed cost of pipelines. This demonstrates that hydrogen delivery mode choice will be site specific especially when pipelines are competitive.

Profit-maximization versus Cost-minimization

Profit maximization and cost minimization are the two approaches that can be taken for the optimization of the supply for biomass hydrogen. There are advantages and disadvantages for each approach. Non-convexity of profit maximizing objective function limited the degree of geographic aggregation and number of potential sites analyzed. Using a non-convex profit maximizing approach required the use of a model solver with the ability to find a global optimum as opposed to local optima. Non-convex problems require significantly more computing power for the same model size (number of variables and equations) than convex problems. A cost-minimization formulation would be convex and would not require the abstraction of the idealized city. That would allow for a greater number of potential production sites.

The profit maximizing model, however, proved useful in determining prices where supplies would be increased. A simple cost minimization does not find the marginal cost of the last hydrogen supplied but finds the average cost for the whole system. The profit maximizing model illuminated larger price differences in the supply curves than would be found using a cost minimization technique. The profit maximizing approach also allows for the easy implementation of a mixed supply system by allowing a generic "backstop" supply to be represented abstractly in the selling price of hydrogen.

Contribution to the literature

This work set out to gain a better understanding of the cost of supplying hydrogen from biomass. Previous cost estimates for biomass hydrogen did not expressly consider the increasing feedstock collection costs with facility size or the cost of hydrogen delivery. The approach taken here was to develop a profit-maximizing model of the full supply chain of hydrogen production from agricultural waste and to demonstrate the model with a case study of rice straw in northern California.

The approach taken here is unique in that the full supply chain is considered in the design of infrastructure for hydrogen production from biomass. This approach allows the design of the supply chain to simultaneously balance feedstock costs, conversion costs and hydrogen delivery costs. Another unique feature is that it uses real-world data on the spatial distribution of the biomass supply and hydrogen demand. This grounding in real geographies provides more realistic cost estimates.

Future directions

Not many trends can be found from a case with only one geographic distribution of biomass supply. The natural extension of this work to gain a more general understanding of biomass-based hydrogen is to analyze a wide variety of feedstock and demand cases. With the results from many case studies, regression analysis could yield trends in optimal facility sizing and hydrogen delivery from simple metrics such as demand and supply densities and network characteristics.

Future model development should focus on improving on the three main limitations of the current model. Development of a stochastic model would greatly improve the quality and robustness of results. A dynamic model taking into account changing demand and supply profiles over time would enable the model to trade-off between the building of oversized facilities with low capacity factors for the initial years of production and the building of small increments of capacity thus restricting the advantages of economies of scale. The last limitation of variable scaling can be addressed by developing a model that incorporates a better cost function for the biomass gasification facility.

Two explorations with the current model would be enlightening. The first is to use the higher compressor scaling factor of 0.9 found in Yang and Ogden (2007) and Simbeck and Chang (2002) to see if two facility optimal solutions become more prevalent with this cost function. The second is to use real-world variations in natural gas prices between cities to set variable prices for hydrogen in the different cities. This effort would demonstrate whether reasonable variability in back-stop technology costs will affect the design of the hydrogen supply infrastructure using agricultural wastes as a feedstock.

The method developed here is general and can be applied to all biomass facility siting problems. A future direction of research will be to adapt the model to biofuel supply chains, such as lignocellulosic ethanol and Fischer-Tropsch bio-diesel, and compare the results for alternative fuels utilizing the same resource base.

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Appendix A

DETERMINATION OF WASTE BIOMASS HYDROGEN POTENTIAL IN CALIFORNIA

Hydrogen production potential from waste biomass resources in California is based on the 2005 biomass resource assessment in von Bernath *et al* (2004). The resource assessment gives the quantity of the technically available biomass of each type in bone dry tons with higher heating values also reported to translate to energy potentials. These estimates for biomass energy potential are converted into hydrogen energy potentials based on the conversion efficiencies reported in Table 39. The map in Figure 1 was produced by assigning the hydrogen production potential from agricultural residues to the counties from which they originate and normalizing based on the area of the county.

Table 39: Assumed Conversion Efficiencies for Different Biomass Resources

Biomass Type	Conversion Efficiency	Comment
Woody	60%	A conservative estimate from the gasification literature.
Straws and Stovers	60%	A conservative estimate from the gasification literature.
Food Wastes/Urban Green Wastes/Meat Processing	15%	Based on 25% efficiency in converting to biogas and 60% efficiency in converting biogas to hydrogen.
Manures	60% biogas	Manure-specific biogas production potentials are given in the report.
Municipal Solid Waste	40% - 54%	Based on a study of slagging gasification for MSW that reported efficiencies dependent on the heating value of input biomass.[11]

[11] Wallman, P. H.; Thorsness, C. B., and Winter, J. D. (1998). Hydrogen Production from Wastes. *Energy*; 23, (4):pp. 271-27

COST CURVE FITS

Chart 16: Gasification Facility Capital Cost Curve Fit

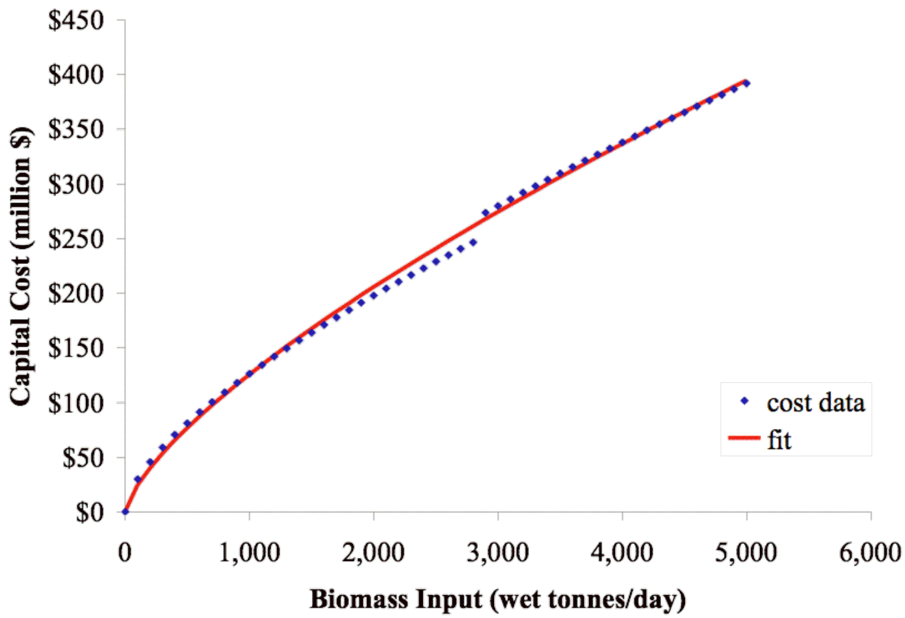


Chart 17: Curve Fit to H2A Liquid Terminal Pump and Pipe Costs

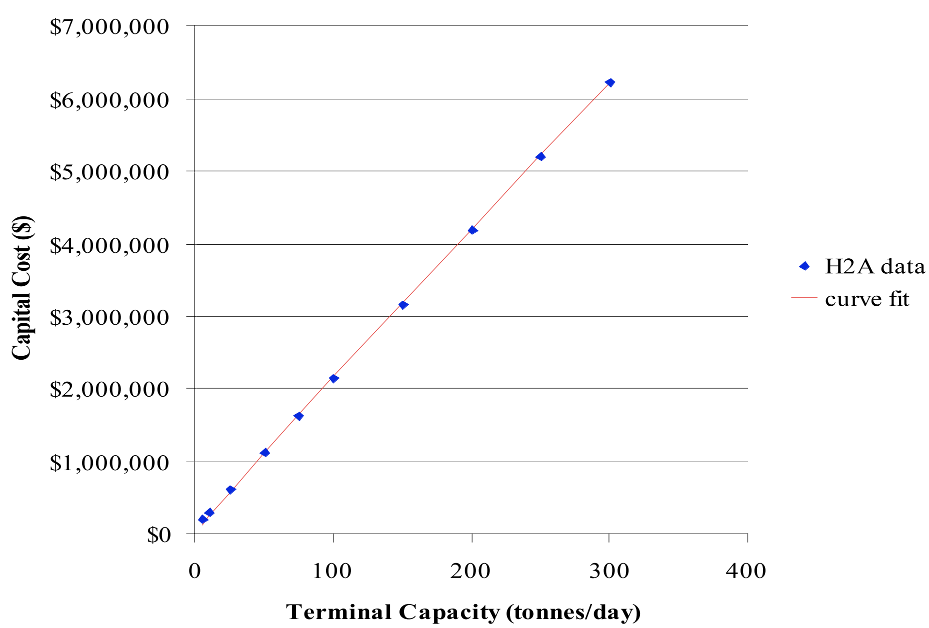


Chart 18: Curve Fit to H2A Liquid Station Evaporator Costs

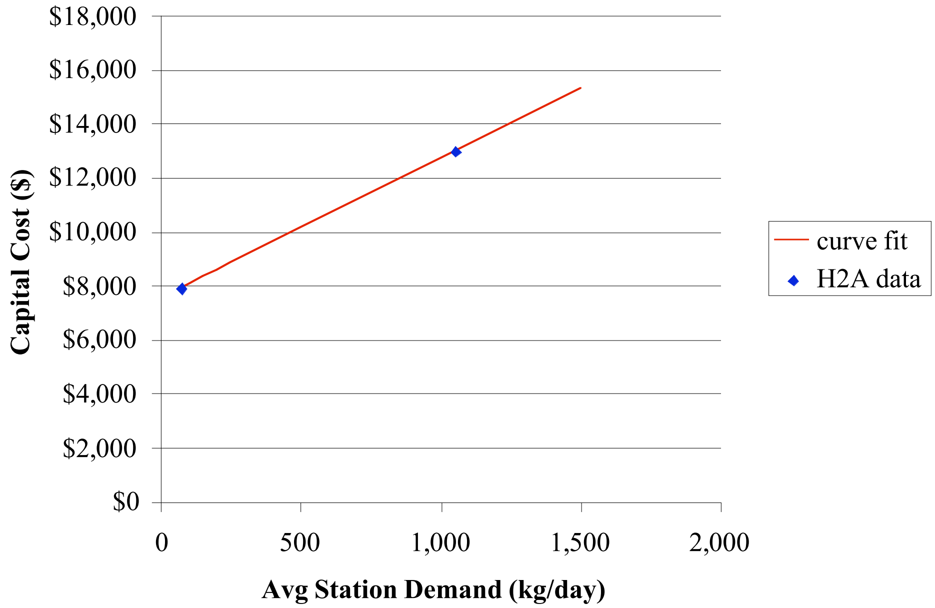


Chart 19: Curve Fit to H2A Liquid Pump Costs at Refueling Station

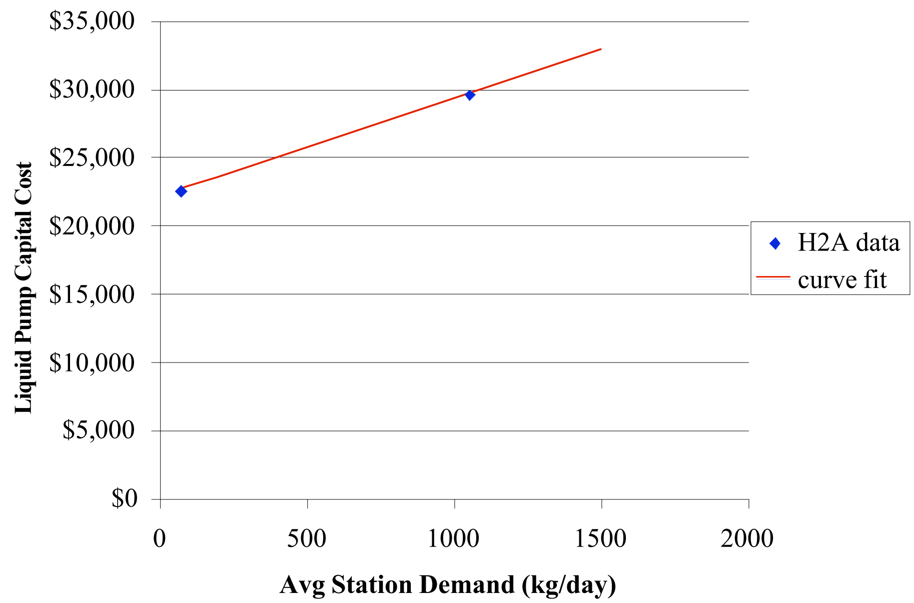
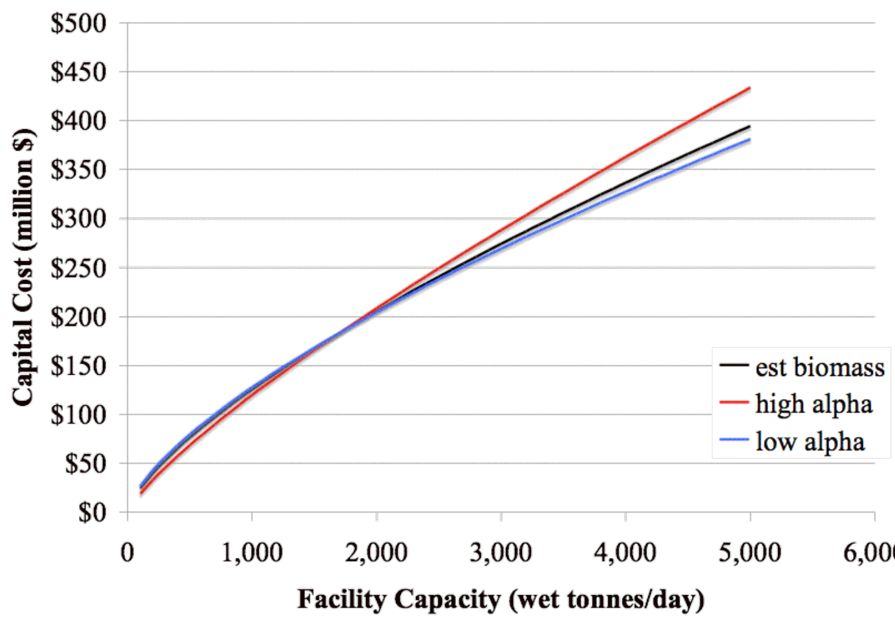
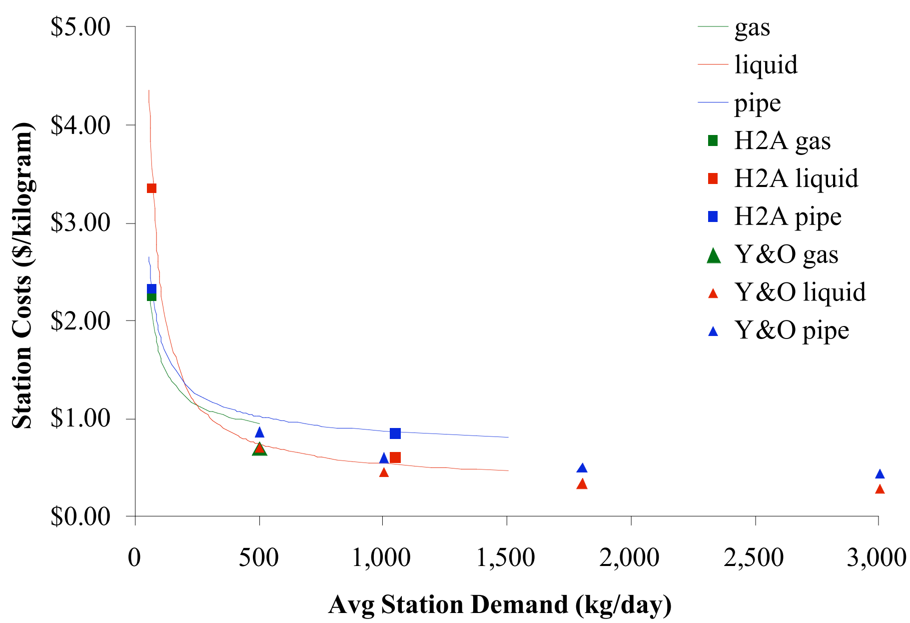


Chart 20: Cost Curves for Gasifier Scaling Factor Sensitivity



Comparison of Refueling Station Cost Curve with H2A and Yang& Ogden (2007)

Chart 21: Comparison of Refueling Station Costs



Appendix B

GAMS MODEL CODE

```
*This model uses idealized city demand nodes and mixed integer/nonlinear cost equations to find
optimal biomass to hydrogen infrastructure

Sets     fields     / field1*field50 /
         sites      / site2, site4, site7, site11, site12 /
         cities     / city1*city26 /
         mode       / gas, liquid / ;

alias(cities, cities2);

*DATA
Parameters
          Price(cities)          cities selling price of H2 (dollars per kg)
          P_elec                 'price of electricity ($/kWh)'                  /0.09/
          P_die                  'price of diesel ($/gal)'                       /2.50/
          irr                    'real internal rate of return'                  /0.10/

         fac_x                   'Facility capital cost inflator'                /1/
         feed_x                  'Feedstock collection cost inflator'            /1/
         trans_pipe              'Cost of transmission pipeline ($/km)'          /384588/
         urban_pipe              'Cost of urban pipeline ($/km)'                 /576881/

          lt_f          'conversion facility lifetime (yrs)'                     /15/
          lt_c          'compressor lifetime (yrs)'                              /20/
          lt_gt         'gas terminal lifetime (yrs)'                            /20/
          lt_lt         'liquid terminal lifetime (yrs)'                         /20/
          lt_pt         'pipeline terminal lifetime (yrs)'                       /20/
          lt_s          'station lifetime (yrs)'                                 /20/
          lt_s_cd       'station compressor and dispenser lifetime (yrs)'        /10/
          lt_p          'pipeline lifetime (yrs)'                                /20/
          lt_cab        'truck cab lifetime (yrs)'                               /5/
          lt_trg        'gas trailer lifetime (yrs)'                             /20/
          lt_trl        'liquid trailer lifetime (yrs)'                          /20/

          CF_f          'capacity factor for conversion facility'                /0.9/
          CF_t          'capacity factor for terminals'                          /0.7/
          CF_s          'capacity factor for stations'                           /0.7/


      f2h               'wet tonnes of rice straw per kg hydrogen capacity'      /61.35/
      epH               'kWh of electricity coproduced per kg hydrogen'          /2.62645/
     feed_avail         'feedstock availability multiplier'                      /.5/

     f_loss             'feedstock loss in collection'                           /0.958/
     t_loss(mode)       'H2 losses at terminal'                                  /gas    0.995
                                                                                  liquid  0.983/
     tp_loss            'H2 losses at terminal'                                  /0.995/
     d_loss(mode)       'H2 losses in distribution'                              /gas    0.995
                                                                                  liquid  0.929/
```

```
      dp_loss            'H2 losses in distribution'                    /0.99/

Yield(fields)            residue yield (tonnes per year)
/ data omitted /
field_rad(fields)
/ data omitted /
field2road(fields)
/ data omitted /
Demand(cities)           station max demand (kg H2 per day)
/ data omitted /
city_rad(cities)         city 'idealized' radius (km)
/ data omitted /

             crf_f, crf_c, crf_gt, crf_lt, crf_pt, crf_s,
            crf_s_cd, crf_p, crf_cab, crf_trg, crf_trl, r_size(cities), supply_tot;

*"Calculation of CRFs"
crf_f = irr/(1-(1+irr)**(-lt_f));
crf_c = irr/(1-(1+irr)**(-lt_c));
crf_gt = irr/(1-(1+irr)**(-lt_gt));
crf_lt = irr/(1-(1+irr)**(-lt_lt));
crf_pt = irr/(1-(1+irr)**(-lt_pt));
crf_s = irr/(1-(1+irr)**(-lt_s));
crf_s_cd = irr/(1-(1+irr)**(-lt_s_cd));
crf_p = irr/(1-(1+irr)**(-lt_p));
crf_cab = irr/(1-(1+irr)**(-lt_cab));
crf_trg = irr/(1-(1+irr)**(-lt_trg));
crf_trl = irr/(1-(1+irr)**(-lt_trl));

*"Calculation of station size for each cluster"
r_size(cities) = min(demand(cities)/10000, 0.10);

*"Calculation of total feedstock supply"
supply_tot = feed_avail*sum(fields, yield(fields));

*"Set the hydrogen selling price the same for all clusters"
Price(cities) = 5;

Parameters
fsdist(fields, sites)       distance between fields and sites
/ data omitted /
scdist(sites, cities)       distance between all sites and all cities
/ data omitted /
scpdist(sites, cities)      distance between site and nearest city
/ data omitted /
ccdist(cities, cities2)     intercity pipeline links
/ data omitted /;

*"Creation of condition sets for pipeline links"
sets    sclim(sites, cities)
        cclim(cities, cities2) ;
sclim(sites, cities)$(scpdist(sites, cities)) = yes;
cclim(cities, cities2)$(ccdist(cities, cities2)) = yes;

*NETWORK DESIGN
variables
```

```
          C(sites)                  facility capacity (kg hydrogen per day)
          T(sites, mode)            terminal capacity (kg hydrogen per day)
          Tp(sites)                 pipe terminal capacity
          S(cities, mode)           supply capacity to city by mode (kg H2 per day)
          Sp(cities)                supply capacity to city by pipeline (kg H2 per day)
          F(fields, sites)          link capacity (tonnes per yr)
          H(sites, cities, mode)    link capacity (kg H2 per day)
          Hp(sites, cities)         link capacity
          Ip(cities, cities2)       link capacity;

binary variable
          Ib(cities, cities2)       pipeline or not variable
          Hb(sites, cities)         pipeline or not variable;

equations
          fcap(fields)              field capacity constraint
          scap(sites)               site capacity constraint
          t1cap(sites)              site terminal capacities constraint 1
          t2cap(sites, mode)        site terminal capacities constraint 2
          t3cap(sites)              site terminal capacities constraint 2
          c1cap(cities, mode)       city capacites constraint
          c2cap(cities)             city cap constraint (pipe)
          cdemand(cities)           station demand constraint

          sflow(sites)              site flow constraint
          cflow(cities)             station flow constraint ;

*"Capacity constraints"
 fcap(fields)..       sum(sites, F(fields, sites)) =l= feed_avail*yield(fields)/100 ;
 scap(sites)..        sum(fields, 100*F(fields, sites))*f2h*f_loss =l=   C(sites)*10000*(CF_f*365) ;
 t1cap(sites)..       sum(mode, T(sites, mode)) + Tp(sites) =e= C(sites);
 t2cap(sites, mode)..    sum(cities, H(sites, cities, mode)) =l= CF_f*t_loss(mode)*T(sites, mode);
 t3cap(sites)..        sum(sclim(sites, cities), Hp(sites, cities)) =l= CF_f*tp_loss*Tp(sites);
 c1cap(cities, mode)..   sum(sites, d_loss(mode)*H(sites, cities, mode))  =e= S(cities, mode) ;
 c2cap(cities)..           sum(sclim(sites, cities), dp_loss*Hp(sites, cities)) + sum(cclim(cities2,
cities), Ip(cities2, cities)) =e= Sp(cities) + sum(cclim(cities, cities2), Ip(cities, cities2));
 cdemand(cities)..        sum(mode, S(cities, mode)) + Sp(cities) =l= Demand(cities)/10000;

*"Flow constraints"
 sflow(sites)..       f_loss*sum(fields, 100*F(fields, sites))*f2h/(365) =e=
                   (sum((cities, mode), 10000*H(sites, cities, mode)/t_loss(mode)) + sum(sclim(sites,
cities), 10000*Hb(sites, cities)*Hp(sites, cities)/tp_loss));
 cflow(cities)..     sum((sites, mode), d_loss(mode)*H(sites, cities, mode)) + sum(sclim(sites,
cities), dp_loss*Hb(sites, cities)*Hp(sites, cities)) + sum(cclim(cities2, cities), Ib(cities2,
cities)*Ip(cities2, cities)) =e= sum(mode, S(cities, mode)) + Sp(cities) + sum(cclim(cities, cities2),
Ib(cities, cities2)*Ip(cities, cities2));

*PROFIT MODEL
Variables                pi                profit;

Positive variables
          rev                 annual revenue
          annual_cost         annual cost
          fCost(sites)        feedstock cost
          sCost(sites)        conversion cost
          tCost(sites)        terminal cost
```

```
            rCost(cities)          refueling cost
            cCost(cities)          local delivery cost
            gCost                  gas delivery cost
            lCost                  liquid delivery cost
            pCost                  pipeline delivery cost;

Equations
            profit, revenue, cost, feed(sites), conv(sites), terminal(sites),
            refuel(cities), gas, liquid, pipe, local(cities);

*"Objective function"

profit..      pi =e= rev - annual_cost;

cost..        annual_cost =e= sum(sites, fCost(sites)) + sum(sites, sCost(sites)) + sum(sites,
tCost(sites)) + sum(cities, cCost(cities))+ sum(cities, rCost(cities)) + gCost + lCost + pCost;
revenue..       rev =e= (sum(cities, Price(cities)*365*10000*(sum(mode, S(cities, mode)) +
Sp(cities)))  + sum(sites, P_elec*epH*365*CF_f*10000*C(sites)))/1000000;

*"Cost components"

feed(sites)..    fCost(sites) =e= sum(fields, (feed_x*(23.11 + 1.05*field_rad(fields)) + ((1.29 +
0.08*field_rad(fields))*P_die) + (0.06 + (P_die*0.008))*(fsdist(fields, sites) +
field2road(fields)))*100*F(fields, sites))/1000000;

conv(sites)..    sCost(sites) =e= ((crf_f + 0.05)*957277*fac_x*((10000*C(sites)/f2H)**0.712) +
crf_f*45.22*5*(10000*C(sites)/f2H) + 1.85*(10000*C(sites)/f2H)*365*CF_f)/1000000;

terminal(sites)..    tCost(sites) =e= ((crf_c +
0.12)*(1.3*40094*(3*((CF_f/CF_t)*0.044871*10000*T(sites, 'gas')/2)**0.6674 +
2*(CF_f*0.067309*10000*T(sites, 'gas')/2)**0.6674))  + (crf_gt +
0.12)*1.76*((1.1*818*((CF_f/CF_t)*10000*T(sites, 'gas'))**0.8) +
(16.14*((CF_f/CF_t)*10000*T(sites, 'gas'))**0.847) + (15.93*(CF_f/CF_t)*10000*T(sites, 'gas'))) +
P_elec*0.758*365*CF_f*10000*T(sites, 'gas')

+ (crf_lt + 0.04)*1.76*(8561800*((CF_f/CF_t)*10000*T(sites, 'liquid')/1000)**0.523 +
96845*((CF_f/CF_t)*1.125*5*10000*T(sites, 'liquid')/1000)**0.824 + 25959*(CF_f*10000*T(sites,
'liquid')/1000)**0.96) + P_elec*9.76*365*CF_f*10000*T(sites, 'liquid')

+ (crf_c + 0.135)*(1.3*40094*(3*(0.024282*10000*Tp(sites)/2)**0.6674 +
2*(0.057657*10000*Tp(sites)/10)**0.6674)) + (crf_pt +
0.04)*(1.72*(1.1*818*(10000*Tp(sites)/2)**0.8)) +
P_elec*365*0.57*CF_f*10000*Tp(sites))/1000000 ;

refuel(cities)..  rCost(cities) =e= ((S(cities, 'gas')/r_size(cities))*((crf_s_cd +
0.1036)*1.45*(309.2*3*((10000*r_size(cities))**0.8823) + 26880) + (crf_s +
0.1036)*1.45*(818*0.3*(10000*r_size(cities))) + 8.3855*10000*r_size(cities) + 15368 +
P_elec*365*1.246*10000*r_size(cities)) +
(S(cities, 'liquid')/r_size(cities))*((crf_s + 0.065)*1.26*(50*(4324+0.334*10000*r_size(cities)) +
1.1*818*0.334*10000*r_size(cities) + 2*(7.1745*10000*r_size(cities) + 22105) +
5.1714*10000*r_size(cities) + 7558) + (crf_s_cd + 0.065)*1.26*(26880*10000*r_size(cities)/350)
+ 16.524*10000*r_size(cities) + 11617 + P_elec*0.33*365*10000*r_size(cities)) +
(Sp(cities)/r_size(cities))*((crf_s_cd+0.063)*1.2*(3*143125*((10000*r_size(cities)/(2*CF_s*750))**
0.667) + 26880*10000*r_size(cities)/350) + (crf_s + 0.063)*1.27*818*0.5*10000*r_size(cities) +
24162 + P_elec*2.146*365*10000*r_size(cities) ))/1000000;
```

```
gas..          gCost =e= (((crf_cab + 0.015)*100000 + 1.5*171696)*(sum(sites, 10000*T(sites,
'gas'))/1465) + (crf_trg + 0.015)*(sum(cities, (S(cities,
'gas')/r_size(cities))*165000*((10000*r_size(cities)/280.3)+1))) + sum((sites, cities), (0.1488 +
0.1036*P_die)*((365*10000*H(sites, cities, 'gas')/280.3)*2*scdist(sites, cities))))/1000000;

liquid..       lCost =e= (((crf_cab + 0.02)*100000 + 1.5*171696)*((sum(sites, 10000*T(sites,
'liquid')))/12178) + (crf_trl + 0.02)*(625000*(sum(sites, 10000*T(sites, 'liquid')))/12178) +
sum((sites, cities),(0.1488 + 0.1036*P_die)*((365*10000*H(sites, cities,
'liquid')/4142.14)*2*scdist(sites, cities))))/1000000 ;

pipe..         pCost =e= (sum(sclim(sites, cities), (crf_p + 0.04)*(trans_pipe/1000000)*Hb(sites,
cities)*scpdist(sites, cities)) + sum(cclim(cities, cities2), (crf_p +
0.04)*(trans_pipe/1000000)*Ib(cities, cities2)*ccdist(cities, cities2)+0.001*Ip(cities, cities2)));

local(cities)..  cCost(cities) =e= (((0.1488 + 0.1036*P_die)*((365*10000*S(cities,
'gas')/280.3)*2*1.42*city_rad(cities)) + (0.1488 + 0.1036*P_die)*((365*10000*S(cities,
'liquid')/(3891.45*0.989))*2*1.42* city_rad(cities)))/1000000) +
(crf_p+0.04)*(urban_pipe/1000000)*2.43*city_rad(cities)*(10000*Sp(cities)/Demand(cities))*((De
mand(cities)/10000)/r_size(cities))**0.4909;

*"Bounds for scaling"
C.lo(sites)                = 0;
C.up(sites)                = sum(fields, f_loss*(f2H/(365*CF_f))*feed_avail*yield(fields)/10000);
T.up(sites, mode)          = C.up(sites);
T.lo(sites, mode)          = 0;
Tp.up(sites)               = C.up(sites);
Tp.lo(sites)               = 0;
S.up(cities, mode)         = Demand(cities)/10000;
S.lo(cities, mode)         = 0;
Sp.up(cities)              = Demand(cities)/10000;
Sp.lo(cities)              = 0;
F.up(fields, sites)        = feed_avail*yield(fields)/100;
F.lo(fields, sites)        = 0;
H.up(sites, cities, mode)= S.up(cities, mode)/d_loss(mode);
H.lo(sites, cities, mode)  = 0;
Hp.up(sites, cities)       = tp_loss*C.up(sites);
Hp.lo(sites, cities)       = 0;
Ip.up(cities, cities2)     = tp_loss*dp_loss*C.up('site2');
Ip.lo(cities, cities2)     = 0;
rev.up = (sum(cities, Price(cities)*365*10000*(sum(mode, S.up(cities, mode)) + Sp.up(cities)))  +
sum(sites, P_elec*epH*365*CF_f*10000*C.up(sites)))/1000000;
fCost.up(sites) = sum(fields, (feed_x*(23.11 + 1.05*field_rad(fields)) + ((1.29 +
0.08*field_rad(fields))*P_die) + (0.06 + (P_die*0.008))*(fsdist(fields, sites) +
field2road(fields)))*100*F.up(fields, sites))/1000000;
sCost.up(sites) = ((crf_f + 0.05)*957277*fac_x*((10000*C.up(sites)/f2H)**0.712) +
crf_f*45.22*5*(10000*C.up(sites)/f2H) + 1.85*(10000*C.up(sites)/f2H)*365*CF_f)/1000000;
tCost.up(sites) = ((crf_c + 0.12)*(1.3*40094*(3*((CF_f/CF_t) *0.044871*10000*T.up(sites,
'gas')/2)**0.6674 + 2*(CF_f*0.067309*10000*T.up(sites, 'gas')/2)**0.6674))  + (crf_gt +
0.12)*1.76*((1.1*818*((CF_f/CF_t)*10000*T.up(sites, 'gas'))**0.8) +
(16.14*((CF_f/CF_t)*10000*T.up(sites, 'gas'))**0.847) + (15.93*(CF_f/CF_t)*10000*T.up(sites,
'gas')))+ P_elec*0.758*365*CF_f*10000*T.up(sites, 'gas') + (crf_lt +
0.04)*1.76*(8561800*((CF_f/CF_t)*10000*T.up(sites, 'liquid')/1000)**0.523 +
96845*((CF_f/CF_t)*1.125*5*10000*T.up(sites, 'liquid')/1000)**0.824 +
25959*(CF_f*10000*T.up(sites, 'liquid')/1000)**0.96) + P_elec*9.76*365*CF_f*10000*T.up(sites,
'liquid') + (crf_c + 0.135)*(1.3*40094*(3*(0.024282*10000*Tp.up(sites)/2)**0.6674 +
2*(0.057657*10000*Tp.up(sites)/10)**0.6674)) + (crf_pt +
```

```
0.04)*(1.72*(1.1*818*(10000*Tp.up(sites)/2)**0.8)) +
P_elec*365*0.57*CF_f*10000*Tp.up(sites))/1000000 ;
rCost.up(cities) = max( (S.up(cities, 'gas')/r_size(cities))*((crf_s_cd +
0.1036)*1.45*(309.2*3*((10000*r_size(cities))**0.8823) + 26880) + (crf_s +
0.1036)*1.45*(818*0.3*(10000*r_size(cities))) + 8.3855*10000*r_size(cities) + 15368 +
P_elec*365*1.246*10000*r_size(cities)), (S.up(cities, 'liquid')/r_size(cities))*((crf_s +
0.065)*1.26*(50*(4324+0.334*10000*r_size(cities)) + 1.1*818*0.334*10000*r_size(cities) +
2*(7.1745*10000*r_size(cities) + 22105) + 5.1714*10000*r_size(cities) + 7558) + (crf_s_cd +
0.065)*1.26*(26880*10000*r_size(cities)/350) + 16.524*10000*r_size(cities) + 11617 +
P_elec*0.33*365*10000*r_size(cities)), (Sp.up(cities)/r_size(cities))*((crf_s_cd +
0.063)*1.2*(3*143125*((10000*r_size(cities)/(2*CF_s*750))**0.667) +
26880*10000*r_size(cities)/350) + (crf_s + 0.063)*1.27*818*0.5*10000*r_size(cities) + 24162 +
P_elec*2.146*365*10000*r_size(cities) ))/1000000;
gCost.up = (((crf_cab + 0.015)*100000 + 1.5*171696)*(sum(sites, 10000*T.up(sites, 'gas'))/1465)
+ (crf_trg + 0.015)*(sum(cities, (S.up(cities,
'gas')/r_size(cities))*165000*((10000*r_size(cities)/280.3)+1))) +sum((sites, cities), (0.1488 +
0.1036*P_die)*((365*10000*H.up(sites, cities, 'gas')/280.3)*2*scdist(sites, cities))))/1000000;
lCost.up = (((crf_cab + 0.02)*100000 + 1.5*171696)*((sum(sites, 10000*T.up(sites,
'liquid')))/12178)+ (crf_trl + 0.02)*(625000*(sum(sites, 10000*T.up(sites, 'liquid')))/12178) +
sum((sites, cities),(0.1488 + 0.1036*P_die)*((365*10000*H.up(sites, cities,
'liquid')/4142.14)*2*scdist(sites, cities))))/1000000 ;
pCost.up = (sum(sclim(sites, cities),(crf_p + 0.04)*(trans_pipe/1000000)*scpdist(sites, cities)) +
sum(cclim(cities, cities2), (crf_p + 0.04)*(trans_pipe/1000000)*ccdist(cities,
cities2)+0.001*Ip.up(cities, cities2)));
cCost.up(cities) = max( ((0.1488 + 0.1036*P_die)*((365*10000*S.up(cities,
'gas')/280.3)*2*1.42*city_rad(cities)))/1000000, ((0.1488 + 0.1036*P_die)*((365*10000*S.up(cities,
'liquid')/(3891.45*0.989))*2*1.42*
city_rad(cities)))/1000000,(crf_p+0.04)*(urban_pipe/1000000)*2.43*city_rad(cities)*(Sp.up(cities)/
r_size(cities))**0.4909);
annual_cost.up = sum(sites, fCost.up(sites)) + sum(sites, sCost.up(sites)) + sum(sites,
tCost.up(sites)) + sum(cities, cCost.up(cities))+ sum(cities, rCost.up(cities)) + gCost.up + lCost.up
+ pCost.up ;

*INITALIZATION
*"The default intialization is equal sized facilities at each site with half of the hydrogen being
delivered by each truck mode and no pipelines. The cost variable are initialized to ensure
feasibility"

C.l(sites)               = min(sum(fields, f_loss*f2H/(365*CF_f)*feed_avail*yield(fields)/10000),
sum(cities,demand(cities)*(.5/(t_loss('gas')*d_loss('gas'))+.5/(t_loss('liquid')*d_loss('liquid')))/1000
0))/5;
T.l(sites, mode)         = C.l(sites)/2;
Tp.l(sites)              = 0;
H.l(sites, cities, mode) = (demand(cities)/sum(cities2, demand(cities2)))*t_loss(mode)*T.l(sites,
mode);
S.l(cities, mode)        = sum(sites, d_loss(mode)*H.l(sites, cities, mode));
Sp.l(cities)             = 0;
F.l(fields, sites)       =
(feed_avail*yield(fields)/supply_tot)*C.l(sites)*((100*365*CF_f)/f2H)/f_loss;
Hp.l(sites, cities)      = 0;
Ip.l(cities, cities2)    = 0;
Hb.l(sites, cities)      = 0;
Ib.l(cities, cities2)    = 0;
rev.l = (sum(cities, Price(cities)*365*10000*(sum(mode, S.l(cities, mode)) + Sp.l(cities)))  +
sum(sites, P_elec*epH*365*CF_f*10000*C.l(sites)))/1000000;
```

```
fCost.l(sites) = sum(fields, (feed_x*(23.11 + 1.05*field_rad(fields)) + ((1.29 +
0.08*field_rad(fields))*P_die) + (0.06 + (P_die*0.008))*(fsdist(fields, sites) +
field2road(fields)))*100*F.l(fields, sites))/1000000;
sCost.l(sites) = ((crf_f + 0.05)*957277*fac_x*((10000*C.l(sites)/f2H)**0.712) +
crf_f*45.22*5*(10000*C.l(sites)/f2H) + 1.85*(10000*C.l(sites)/f2H)*365*CF_f)/1000000;
tCost.l(sites) = ((crf_c + 0.12)*(1.3*40094*(3*((CF_f/CF_t)*0.044871*10000*T.l(sites,
'gas')/2)**0.6674 + 2*(CF_f*0.067309*10000*T.l(sites, 'gas')/2)**0.6674))  + (crf_gt +
0.12)*1.76*((1.1*818*((CF_f/CF_t)*10000*T.l(sites, 'gas'))**0.8) +
(16.14*((CF_f/CF_t)*10000*T.l(sites, 'gas'))**0.847) + (15.93*(CF_f/CF_t)*10000*T.l(sites,
'gas')))+ P_elec*0.758*365*CF_f*10000*T.l(sites, 'gas') + (crf_lt +
0.04)*1.76*(8561800*((CF_f/CF_t)*10000*T.l(sites, 'liquid')/1000)**0.523 +
96845*((CF_f/CF_t)*1.125*5*10000*T.l(sites, 'liquid')/1000)**0.824 +
25959*(CF_f*10000*T.l(sites, 'liquid')/1000)**0.96) + P_elec*9.76*365*CF_f*10000*T.l(sites,
'liquid') + (crf_c + 0.135)*(1.3*40094*(3*(0.024282*10000*Tp.l(sites)/2)**0.6674 +
2*(0.057657*10000*Tp.l(sites)/10)**0.6674)) + (crf_pt +
0.04)*(1.72*(1.1*818*(10000*Tp.l(sites)/2)**0.8)) +
P_elec*365*0.57*CF_f*10000*Tp.l(sites))/1000000 ;
rCost.l(cities) = ((S.l(cities, 'gas')/r_size(cities))*((crf_s_cd +
0.1036)*1.45*(309.2*3*((10000*r_size(cities))**0.8823) + 26880) + (crf_s +
0.1036)*1.45*(818*0.3*(10000*r_size(cities))) + 8.3855*10000*r_size(cities) + 15368 +
P_elec*365*1.246*10000*r_size(cities)) + (S.l(cities, 'liquid')/r_size(cities))*((crf_s +
0.065)*1.26*(50*(4324+0.334*10000*r_size(cities)) + 1.1*818*0.334*10000*r_size(cities) +
2*(7.1745*10000*r_size(cities) + 22105) + 5.1714*10000*r_size(cities) + 7558) + (crf_s_cd +
0.065)*1.26*(26880*10000*r_size(cities)/350) + 16.524*10000*r_size(cities) + 11617 +
P_elec*0.33*365*10000*r_size(cities)) + (Sp.l(cities)/r_size(cities))*((crf_s_cd +
0.063)*1.2*(3*143125*((10000*r_size(cities)/(2*CF_s*750))**0.667) +
26880*10000*r_size(cities)/350) + (crf_s + 0.063)*1.27*818*0.5*10000*r_size(cities) + 24162 +
P_elec*2.146*365*10000*r_size(cities) ))/1000000;
gCost.l = (((crf_cab + 0.015)*100000 + 1.5*171696)*(sum(sites, 10000*T.l(sites, 'gas'))/1465) +
(crf_trg + 0.015)*(sum(cities, (S.l(cities,
'gas')/r_size(cities))*165000*((10000*r_size(cities)/280.3)+1))) + sum((sites, cities), (0.1488 +
0.1036*P_die)*((365*10000*H.l(sites, cities, 'gas')/280.3)*2*scdist(sites, cities))))/1000000;
lCost.l = (((crf_cab + 0.02)*100000 + 1.5*171696)*((sum(sites, 10000*T.l(sites, 'liquid')))/12178) +
(crf_trl + 0.02)*(625000*(sum(sites, 10000*T.l(sites, 'liquid')))/12178) + sum((sites, cities),(0.1488
+ 0.1036*P_die)*((365*10000*H.l(sites, cities, 'liquid')/4142.14)*2*scdist(sites, cities))))/1000000 ;
pCost.l = (sum(sclim(sites, cities), (crf_p + 0.04)*(trans_pipe/1000000)*Hb.l(sites,
cities)*scpdist(sites, cities)) + sum(cclim(cities, cities2), (crf_p +
0.04)*(trans_pipe/1000000)*Ib.l(cities, cities2)*ccdist(cities, cities2)+0.001*Ip.l(cities, cities2)));
cCost.l(cities)  = (((0.1488 + 0.1036*P_die)*((365*10000*S.l(cities,
'gas')/280.3)*2*1.42*city_rad(cities)) + (0.1488 + 0.1036*P_die)*((365*10000*S.l(cities,
'liquid')/(3891.45*0.989))*2*1.42* city_rad(cities)))/1000000) +
(crf_p+0.04)*(urban_pipe/1000000)*2.43*city_rad(cities)*(10000*Sp.l(cities)/Demand(cities))*((De
mand(cities)/10000)/r_size(cities))**0.4909;
annual_cost.l = sum(sites, fCost.l(sites)) + sum(sites, sCost.l(sites)) + sum(sites, tCost.l(sites)) +
sum(cities, cCost.l(cities))+ sum(cities, rCost.l(cities)) + gCost.l + lCost.l + pCost.l;
pi.l = rev.l - annual_cost.l;

*SOLVER TWEAKING
option MINLP = BARON;  *"Defines the solver to be used."
Model    WB2Hlin      /all/;  *"Defines the model to be all preceding equations."
option optcr = 0.001 ;   *"Sets criteria for optimality to be within 0.1% of best solution"
option sys12 = 1;
option reslim = 28800;  *"Limits model runs to 8 hours."


Solve    WB2Hlin    using MINLP maximizing pi;
```