ANL/ESD/05-2

Hydrogen Demand, Production, and Cost by Region to 2050

prepared by
Center for Transportation Research
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August 3, 2005

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ACKNOWLEDGMENTS

The preparation of this report on regional H_2 demand, production, and cost and the development of the Regional H_2 Model 1.0 have been funded by the Office of Planning, Budget and Analysis of the Office of Energy Efficiency and Renewable Energy, U.S. Department of Energy. Philip Patterson has been the primary sponsor of this analytical effort, and we wish to thank him for his extensive support. We would also like to thank numerous reviewers of past versions of this draft, related papers, and presentations, particularly Steve Plotkin, Argonne National Laboratory. The authors are solely responsible for the report's contents.

SUMMARY

This report presents an analysis of potential hydrogen (H_2) demand, production, and cost by region (i.e., U.S. Census Division) to 2050.[1] The analysis was conducted to (1) address the Energy Information Administration's (EIA's) request for regional H_2 cost estimates that will be input to its energy modeling system and (2) identify key regional issues associated with the use of H_2 that need further study. Hydrogen costs may vary substantially by region. Many feedstocks may be used to produce H_2, and the use of these feedstocks is likely to vary by region. For the same feedstock, regional variation exists in capital and energy costs. Furthermore, delivery costs are likely to vary by region: some regions are more rural than others, and so delivery costs will be higher. However, to date, efforts to comprehensively and consistently estimate future H_2 costs have not yet assessed regional variation in these costs.

To develop the regional cost estimates and identify regional issues requiring further study, we developed a H_2 demand scenario (called "Go Your Own Way" [GYOW]) that reflects fuel cell vehicle (FCV) market success to 2050 and allocated H_2 demand by region and within regions by metropolitan versus non-metropolitan areas. Because we lacked regional resource supply curves to develop our H_2 production estimates, we instead developed regional H_2 production estimates by feedstock by (1) evaluating region-specific resource availability for centralized production of H_2 and (2) estimating the amount of FCV travel in the non-metropolitan areas of each region that might need to be served by distributed production of H_2. Using a comprehensive H_2 cost analysis developed by SFA Pacific, Inc., as a starting point, we then developed cost estimates for each H_2 production and delivery method by region and over time (SFA Pacific, Inc. 2002). We assumed technological improvements over time to 2050 and regional variation in energy and capital costs. Although we estimate substantial reductions in H_2 costs over time, our cost estimates are generally higher than the cost goals of the U.S. Department of Energy's (DOE's) hydrogen program.

The result of our analysis, in particular, demonstrates that there may be substantial variation in H_2 costs between regions: as much as \$2.04/gallon gasoline equivalent (GGE) by the time FCVs make up one-half of all light-vehicle sales in the GYOW scenario (2035–2040) and \$1.85/GGE by 2050 (excluding Alaska) (see Figure S-1 and Table 4.7). Given the assumptions we have made, our analysis also shows that there could be as much as a \$4.82/GGE difference in H_2 cost between metropolitan and non-metropolitan areas by 2050 (national average). Our national average cost estimate by 2050 is \$3.68/GGE, but the average H_2 cost in metropolitan areas in that year is \$2.55/GGE and that in non-metropolitan areas is \$7.37/GGE (see Figure S-2 and Table 4.9).

For these estimates, we assume that the use of natural gas to produce H_2 is phased out. This phase-out reflects the desire of DOE's Office of Hydrogen, Fuel Cells and Infrastructure

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[1] We estimate cost, not price. Prices are market-driven and include taxes. Our costs are not market-driven and do not include taxes.

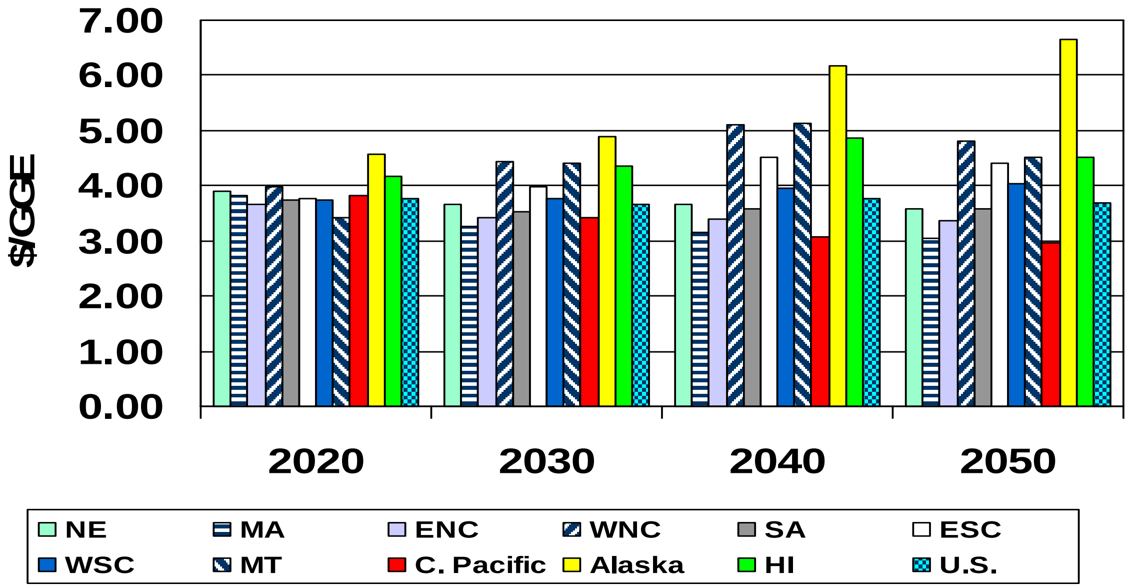

FIGURE S-1 Final Delivered H_2 Costs in GYOW by Region

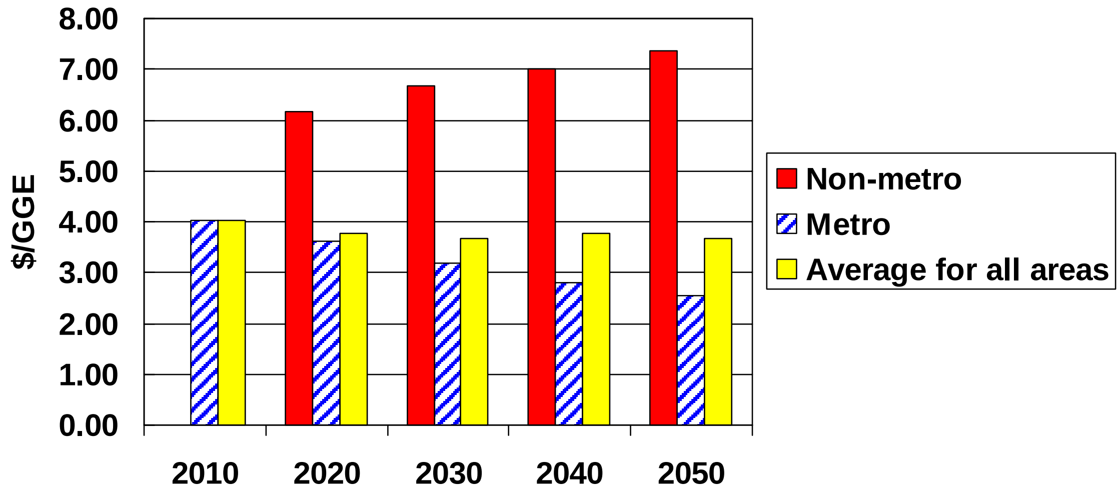

FIGURE S-2 Final Delivered H_2 Cost in GYOW: U.S. Summary by Metropolitan versus Non-Metropolitan Areas

Technologies (OHFCIT) to eliminate reliance on natural gas for H_2 production. We conducted a sensitivity run in which we allowed natural gas to continue to be used through 2050 for distributed production of H_2 to see what effect changing that assumption had on costs. In effect, natural gas is used for 66% of all distributed production of H_2 in this run. The national average cost is reduced to $3.10/GGE, and the cost in non-metropolitan areas is reduced from $7.37/GGE to $4.90, thereby reducing the difference between metropolitan and non-metropolitan areas to $2.35/GGE (see Figure S-3 and Table 4.11). Although the cost difference is reduced, it is still substantial. Regional differences are similarly reduced, but they also remain substantial.

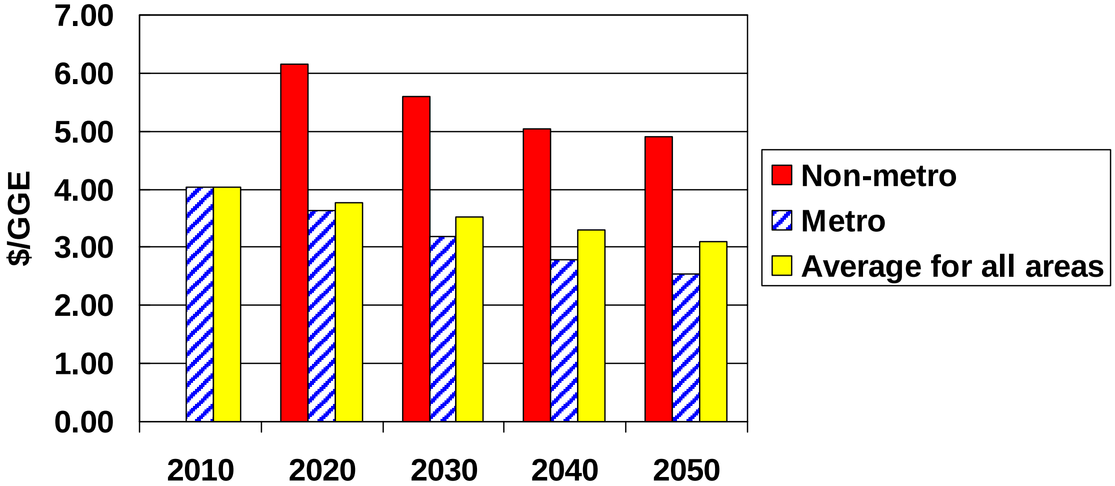

FIGURE S-3 Sensitivity Run Assuming Continued Use of Natural Gas for Distributed Production: Final Delivered H_2 Costs in the United States

We also conducted a sensitivity run in which we cut in half our estimate of the cost of distributed production of H_2 from electrolysis (our highest-cost production method). In this run, our national average cost estimate is reduced even further, to $2.89/GGE, and the cost in non-metropolitan areas is reduced to $4.01/GGE. Thus, the difference between metropolitan and non-metropolitan areas is reduced to $1.46/GGE, but it remains substantial (see Table 4.11).

Given that these sensitivity runs demonstrate continued substantial differences between regions and between metropolitan and non-metropolitan areas, we believe that we have demonstrated the potential for significant differences in H_2 cost between and within regions. We think the potential for these differences needs to be addressed in future H_2 cost analyses.

Finally, there are many issues involved in adequately estimating what resources might be used to produce H_2, how H_2 demand will grow over time, and what H_2 costs will be regionally and nationally. We have compiled a list of issues that reflects both issues that we faced and others that we believe need to be addressed to develop improved estimates of regional H_2 demand, production, and cost.

HYDROGEN DEMAND, PRODUCTION, AND COST BY REGION TO 2050

1 INTRODUCTION

A scenario of hydrogen (H_2) production and demand to 2050 by U.S. Census Division ("region" in this report) has been developed, and regional H_2 costs per gallon gasoline equivalent (GGE) have been estimated for that scenario. Hydrogen cost estimates are essentially the costs to produce H_2 and exclude taxes. We developed this scenario and generated cost estimates at the request of the U.S. Department of Energy (DOE), Office of Energy Efficiency and Renewable Energy, Office of Planning, Budget and Analysis. The purpose of developing this scenario and generating regional cost estimates was twofold:

1. *To provide the Energy Information Administration (EIA) with H_2 cost estimates that vary by region and over time*. In the past, when EIA has modeled the use of H_2 in fuel cell vehicles (FCVs) for its Annual Energy Outlook (AEO) projections, it has used a single H_2 price across all U.S. Census Divisions and across time. EIA indicated that if H_2 cost estimates could be developed that varied by region and over time, it would use them. The regional cost estimates developed in the analysis reported here were provided to EIA, which used them in development of the AEO 2005 (Maples 2004).

2. *To identify key regional issues associated with the production and use of H_2*. Considerable analytical effort is under way to develop comprehensive and consistent estimates of the future costs of H_2 and to evaluate alternative transitions to the use of FCVs (Mann 2004, Greene et al. 2004, and Woods 2005). Although at least two of these efforts will examine regional (as defined in this report) variations in H_2 production, demand, and costs, to date they have not. The analysis reported here was conducted to help identify regional issues that need to be considered by these other analytical efforts.

In this report, we describe the assumptions we made in the development of the scenario and its H_2 cost estimates. Most of the discussion focuses on how the production and cost estimates were derived for a given demand scenario (described in Section 2). We present the final production scenario and cost estimates. We also summarize key analytical issues that need to be addressed in developing such estimates.

We used an Excel spreadsheet model (the Regional H_2 Model, version 1.0) to develop the final production scenario and cost estimates. Other H_2 demand scenarios can be input to the model and alternative costs estimated. Where appropriate in the following sections, we indicate where other inputs (besides H_2 demand) to the model can be varied.

2 HYDROGEN DEMAND SCENARIO

2.1 TOTAL DEMAND BY REGION

Table 2.1 and Figure 2.1 present three scenarios of potential H_2 demand from light-duty vehicles over time. One is the "EIA reference" case, which shows very little demand and is therefore uninteresting from the point of view of developing H_2 cost estimates and fleshing out regional issues. Another scenario is called the "President's Hydrogen Fuel Initiative" in which nearly 100% of light vehicle stock in 2050 is estimated to be FCVs. A third is called the "Go Your Own Way" (GYOW) scenario, the name of which was developed in the joint DOE/Natural Resources Canada 2050 study (Patterson et al. 2003). In GYOW, FCV sales begin in 2015 and reach 50% of all light vehicle sales by 2035, when they plateau. (Some FCVs will be on the road by 2010, but in limited niche markets.)

We have chosen to focus our analysis on the GYOW scenario because it is an optimistic, but intermediate, scenario of H_2 demand. Using a stock model (VISION), we estimated that in that scenario, approximately 50% of all light vehicle stock will be FCVs by 2050 (Singh, Vyas, and Steiner 2003). The H_2 demand of GYOW is substantial: nearly 6 quads (over 42 million metric tons or 45 billion GGE) by 2050. We allocated this demand by state and region. Table 2.2 lists the states included in each region, and Figure 2.2 presents the regions. We split Alaska and Hawaii from the Pacific region totals and treated these non-contiguous states as separate regions.

Although the VISION model generates annual fuel use estimates, we only input its H_2 demand estimates for the years 2010, 2020, 2030, 2040, and 2050 to the Regional H_2 Model. (The year 2010 estimates are actually EIA's estimates.)

The regional allocation of H_2 demand was made according to the year 2000 motor gasoline use; the regional shares were held constant over time (EIA 2000). In effect, we assumed that FCVs would penetrate the market at the same rate in the various U.S. regions over time (which we recognize is unlikely). Table 2.3 presents motor gasoline use in 2000 by U.S. region and H_2 demand by 2050 in the GYOW scenario. Figure 2.3 presents regional H_2 demand over time.

2.2 WITHIN-REGION DEMAND

We further allocated H_2 demand within regions by metropolitan and non-metropolitan areas. We made this allocation because of our assumption that, in a scenario of significant FCV market penetration, FCVs will be used in the same manner as today's vehicles and thus will be used in both metropolitan and non-metropolitan areas. The cost of supplying H_2 to metropolitan and non-metropolitan areas may vary considerably.

We used the metropolitan area designations provided by the U.S. Census, effective January 28, 2002 (U.S. Census Bureau 2002). The allocation of H_2 demand within regions by

TABLE 2.1 Details of Three Hydrogen Demand Scenarios

Parameter/Scenario	EIA AEO-2003			GYOW			President's Hydrogen Fuel Initiative		
	2015	2030	2050	2015	2030	2050	2015	2030	2050
Market Penetration Assumptions									
Year Light-Duty (LD) Fuel Cell Vehicle (FCV) Sales Start		2005			2015			2018	
Year FCVs Reach 50% LD Sales		Never			2035			2025	
FCV % of LD Sales	0.009	NA	NA	0.4	47.5	50	0	77.8	100
FCV % of LD Stock	0.004	NA	NA	0.027	19.4	49.5	0	37.9	96.7
Stock (10^6)									
Total Fuel Cell (FC) Cars	0.009	NA	NA	0.035	30	86	0	58	169
Total FC Light Trucks	0.003	NA	NA	0.034	29	89	0	58	173
Total FC Light-Duty Vehicles (LDVs)	0.012	NA	NA	0.069	59	175	0	116	342
Calculation Method		Spreadsheet			VISION Model			VISION Model	
Fuel Economy (mi/GGE)									
New FC Cars (EPA-test)	49.1	NA	NA	55.8	74.6	80.3	NA	71.2	85.5
New FC Lt Trks (EPA-test)	42.3	42.1	NA	41.5	55.4	59.7	NA	53.0	63.6
FC Car Stock (on-rd)	NA	NA	NA	46.4	58.9	66.7	NA	57.0	65.0
FC Lt Trk Stock (on-rd)	NA	NA	NA	35.6	44.8	50.7	NA	43.3	49.4
FC LD Stock (on-rd)	NA	NA	NA	40.6	51.0	57.5	NA	49.4	56.1
Miles Traveled (10^9)									
FC Cars	NA	NA	NA	0.4	428	1,292	NA	837	2,532
FC Light Trucks	NA	NA	NA	0.5	414	1,320	NA	810	2,568
Total FC LDVs	0.146	NA	NA	0.9	842	2,612	NA	1,647	5,100

TABLE 2.1 (Cont.)

	EIA AEO-2003			GYOW			President's Hydrogen Fuel Initiative		
Parameter/Scenario	**2015**	**2030**	**2050**	**2015**	**2030**	**2050**	**2015**	**2030**	**2050**
Miles/Vehicle									
FC Cars	NA	NA	NA	13,724	14,384	15,000	NA	14,384	15,000
FC Lt Trks	NA	NA	NA	12,918	14,055	14,908	NA	14,054	14,840
Total FC LDVs	12,436	NA	NA	13,328	14,220	14,953	NA	14,220	14,919
H_2 Fuel Use, Million Metric Tons									
FC Cars									
FC Lt Trks									
Total FC LDVs	0.0036	0.03	0.96	0.02	15.35	42.18	NA	31.01	84.55
H_2 Fuel Use, Quads (HHV)									
FC Cars	NA	NA	NA	0.001	0.91	2.42	NA	1.83	4.87
FC Lt Trks	NA	NA	NA	0.002	1.16	3.25	NA	2.34	6.50
Total FC LDVs	0.00049	0.005	0.129	0.003	2.06	5.67	NA	4.17	11.37

NA = Not applicable

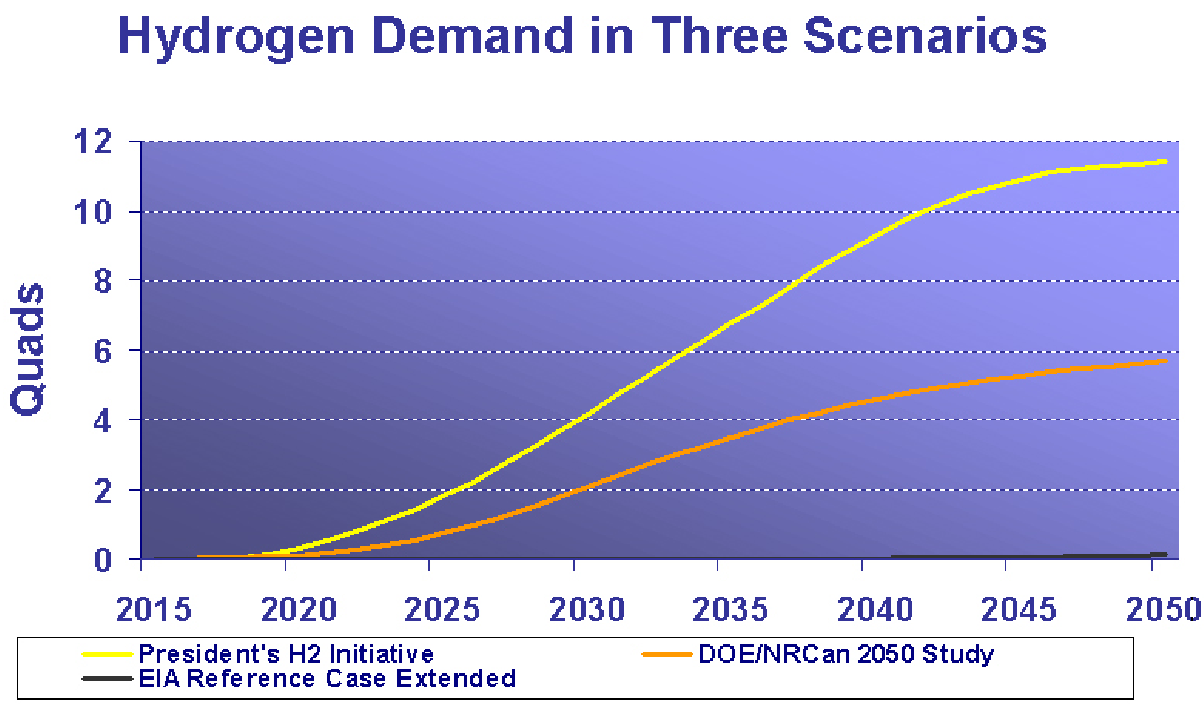

FIGURE 2.1 Total Demand of Three H_2 Scenarios, 2015–2050

TABLE 2.2 Census Bureau Divisions

Division 1	Division 2	Division 3	Division 4	Division 5
New England	**Middle Atlantic**	**East North Central**	**West North Central**	**South Atlantic**
Connecticut	New Jersey	Illinois	Iowa	Delaware
Maine	New York	Indiana	Kansas	District of Columbia
Massachusetts	Pennsylvania	Michigan	Minnesota	Florida
New Hampshire		Ohio	Missouri	Georgia
Rhode Island		Wisconsin	Nebraska	Maryland
Vermont			North Dakota	North Carolina
			South Dakota	South Carolina
				Virginia
				West Virginia
Division 6	**Division 7**	**Division 8**	**Division 9**	
East South Central	**West South Central**	**Mountain**	**Pacific**	
Alabama	Arkansas	Arizona	Alaska	
Kentucky	Louisiana	Colorado	California	
Mississippi	Oklahoma	Idaho	Hawaii	
Tennessee	Texas	Montana	Oregon	
		Nevada	Washington	
		New Mexico		
		Utah		
		Wyoming		

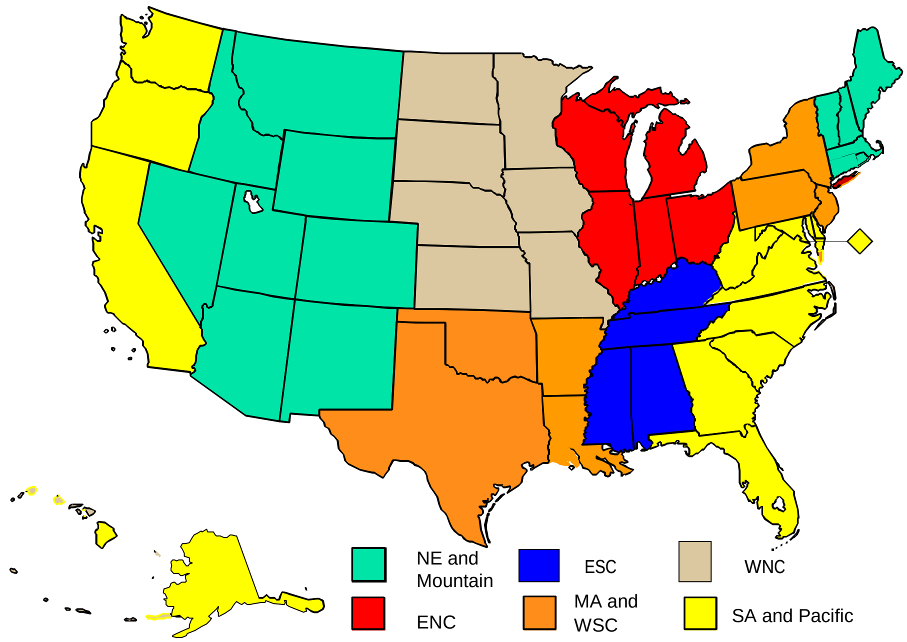

FIGURE 2.2 U.S. Census Divisions (NE = New England, ESC = East South Central, WNC = West North Central, ENC = East North Central, MA = Middle Atlantic, WSC = West South Central, and SA = South Atlantic)

TABLE 2.3 Total GYOW Demand and Production in 2050 by U.S. Region

U.S. Census Divisions	Share of Total Gasoline Use in 2000	H_2 Demand in 2050 (Quads)
New England	0.048	0.275
Middle Atlantic	0.111	0.632
East North Central	0.159	0.899
West North Central	0.078	0.444
South Atlantic	0.199	1.126
East South Central	0.068	0.388
West South Central	0.123	0.695
Mountain	0.066	0.377
Pacific (contiguous states only)	0.143	0.809
Alaska	0.002	0.011
Pacific	0.003	0.017
Total	1.00	5.673

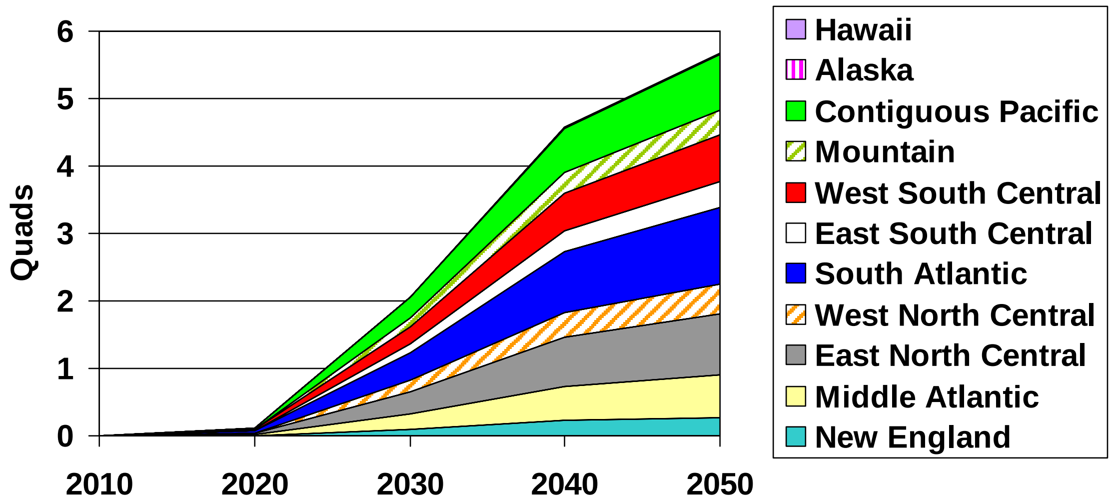

Figure 2.3 Regional H_2 Demand in GYOW

metropolitan and non-metropolitan areas was made on the basis of estimates of county-level light-vehicle vehicle miles traveled (VMT) provided by the U.S. Environmental Protection Agency (EPA) (EPA 2004). (In the New England states, in some instances, only part of a county is designated by the Census as metropolitan. For our purposes, a county that is "partly" metropolitan is considered entirely metropolitan.) Figure 2.4 illustrates the results of these assumptions. Of all light vehicle (LV) travel in the United States, 24% is in non-metropolitan areas, and thus we assume that ultimately 24% of all H_2 demand will be generated in non-metropolitan areas. However, regional variation in that demand will be great, as illustrated in Figure 2.4.

Although we assume that ultimately 24% of all H_2 demand will be generated in non-metropolitan areas, we expect that there will be a gradual build-up to that share. Specifically, we assume that the only non-metropolitan travel by FCVs in 2020 will be along non-metropolitan interstates. Approximately 5% of all LV travel is along such interstates. In 2030, we assume that approximately 14% of all FCV travel will be in non-metropolitan areas and by 2040, 24% will be in non-metropolitan areas. Table 2.4 presents the final non-metropolitan H_2 demand by year and region.

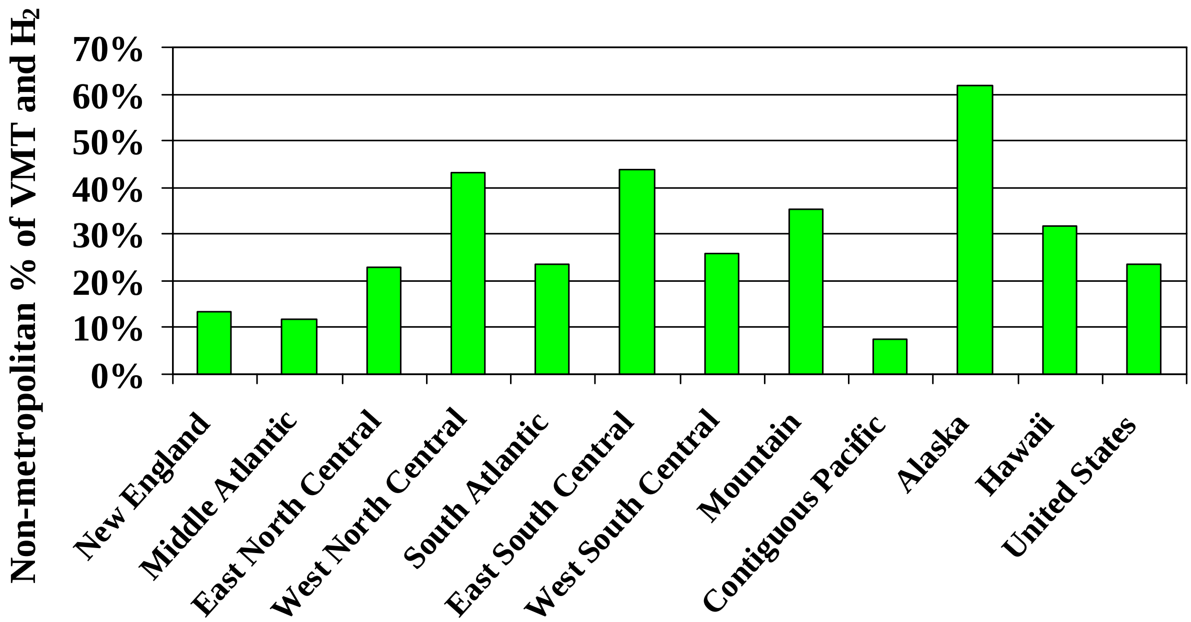

FIGURE 2.4 Non-Metropolitan Percentage of VMT and H_2 Demand by Region

TABLE 2.4 Non-Metropolitan LV Travel and Assumed FCV Travel and Demand

Region	2002 Share of LV Travel on Non-Metropolitan Interstates (%)	2002 Share of LV Travel in Non-Metropolitan Areas (%)	Assumed Share of FCV Travel and Demand in Non-Metropolitan Areas		
			2020 (%)	2030 (%)	2040 and 2050 (%)
New England	2.3	13.4	2.3	8.0	13.4
Middle Atlantic	2.7	11.8	2.7	7.1	11.8
East North Central	4.8	22.9	4.8	13.7	22.9
West North Central	8.7	43.1	8.7	25.9	43.1
South Atlantic	5.5	23.6	5.5	14.2	23.6
East South Central	7.8	43.8	7.8	26.3	43.8
West South Central	6.3	25.9	6.3	15.5	25.9
Mountain	10.3	35.4	10.3	21.2	35.4
Contiguous Pacific	2.0	7.5	2.0	4.5	7.5
Alaska	18.2	61.7	18.2	37.0	61.7
Hawaii	0.0	31.7	0.0	19.0	31.7
U.S. Total	5.3	23.7	5.3	14.2	23.7

3 HYDROGEN PRODUCTION

3.1 OVERVIEW OF KEY ASSUMPTIONS USED IN ESTIMATING THE RESOURCES USED TO PRODUCE HYDROGEN

Hydrogen can be produced from many resource fuels or feedstocks. Ideally, regional resource supply curves would be used to estimate which resources will be used to produce various volumes of H_2 in the different regions. Given the lack of a comprehensive set of such curves at this time, we developed an alternative method of estimating the resources used in different regions to produce H_2. Our method is based on a number of assumptions. We highlight the key assumptions below and discuss them in further detail in subsequent sections of this report. The key assumptions are:

1. Each region will produce sufficient H_2 to meet the region's demand. We do not expect that to be the case ultimately, but we have chosen to make this assumption to simplify this initial analysis. We do think that, given all the potential sources of H_2, a great deal of H_2 may be produced from within-region resources.

2. Relative resource availability in a region (i.e., the relative abundance of coal versus natural gas versus renewables, etc.) determines the likelihood of each resource being used to produce H_2 in that region. Again, the main reason for taking this approach is that regional supply curves for all the resources of interest are not available.

3. Steam-reforming of natural gas and electrolysis (both centralized and distributed) will be the methods used to produce H_2 initially when H_2 demand is very low.

4. Both centralized and distributed production of H_2 will be used throughout the time frame of this analysis.

5. Centralized production will provide the H_2 used in metropolitan areas and some non-metropolitan areas, while distributed production (H_2 produced at service stations) will meet a large share of non-metropolitan area demand.

6. Use of natural gas to produce H_2 will be phased out completely by 2050.

In Sections 3.2–3.4, we discuss how we (1) characterized regional resource fuel availability, (2) estimated the share of H_2 produced via distributed production, and (3) estimated what resources would be used to produce H_2 (both distributed and central) over time. In Section 3.5, we present a final estimate of H_2 production by resource fuel and centralized versus distributed production.

3.2 RESOURCES USED IN H_2 PRODUCTION

As stated above, we assume that steam-reforming of natural gas and electrolysis (both centralized and distributed) will be the methods used to produce H_2 initially when H_2 demand is very low. Over time, as H_2 demand grows, H_2 will be produced from divergent sources, particularly coal (with carbon sequestration); renewables; and thermochemical water splitting by using advanced, high-temperature nuclear power. Because resource availability varies across the country, different levels of each resource will be used across regions. (The levels of each resource will also be affected by the cost of producing the resource, but we do not account for that in this analysis.)

We used state-level resource information to rate the U.S. regions, as described below. We separate Alaska and Hawaii from the Pacific region, and so we actually characterize 11 regions.

1. For **coal**, EIA provides "estimated recoverable reserves" by state (EIA 2001). On the basis of these reserve amounts, we categorized the states into four groups: "a" (extensive reserves and therefore highly likely to use first and longest), "b" (moderate reserves and therefore likely to use if possible), "c" (limited reserves and therefore likely to look for other alternatives), and "d" (no reserves and therefore must look for other alternatives). Once each state was rated, the U.S. regions were characterized as "A," "B," "C," or "D" for coal based on the highest ranking achieved by any state within a region. The presumption underlying this characterization is that the coal resources of a state will not be limited to H_2 production for that state alone, but it will be used for H_2 production for closely associated states as well. The result of this characterization is that 5 of the 11 regions are ranked "A," 3 "B," 1 "C," and 2 "D" — not an unusual characterization, given that the United States is a coal-rich country.

2. For **renewables**, we characterized the biomass, wind, and solar resources of each state and region and then developed an overall renewables rating for each region. Oak Ridge National Laboratory (ORNL) has developed estimates of the cumulative volume of biomass that can be produced within each state at \$50 or less per dry ton (ORNL 2003). The National Renewable Energy Laboratory (NREL) has classified wind resource potential across the country. NREL's U.S. wind resource map was reviewed, and state-level resource potential estimates were developed (EERE 2003). Similarly, NREL has classified national solar resources. Maps of these resources were reviewed, and state-level resource potential estimates were developed (NREL 2003).

   For each of these three resources, these state-level volumes and resource potential estimates were used to classify states as "a" (excellent resource), "b" (moderate) "c" (limited), or "d" (none or very little) in a manner very similar to that used for coal classification. Then, as with coal, the U.S. census regions were characterized as "A," "B," "C," or "D" for biomass, wind, and solar, on the basis of the highest ranking achieved by any state within a region. The presumption underlying this characterization is that the individual renewable resources of a state will not be limited to H_2 production for that state alone, but it will be used for H_2 production for closely associated states as well. The result of this characterization is that 5 of the 11 regions were ranked “A” for biomass, 5 for wind, and 4 for solar.

Once these estimates were made, each region was similarly categorized for renewables as a whole. Given that in the AEO 2003 EIA estimates a very small contribution by solar technology to electricity generation and end-use sector energy use relative to biomass and wind in 2025, we based the regional renewable classification on just the regional biomass and wind characterizations (EIA 2003a). The result of this characterization is that 7 of the 11 regions are ranked “A,” 3 “B,” and 1 “C” for renewable resources.

3. For **H_2 generation via thermochemical water splitting using advanced, high-temperature nuclear reactors**, we assumed that these reactors will only be built in states with existing nuclear power plants. EIA data were used to develop a list of those states, and each state was classified as “yes” or “no” (EIA 2003b). We then used a weighted average to characterize a region’s propensity to use nuclear power to generate H_2. The weighted average accounted for each state’s potential level of H_2 demand (as estimated by its proportion of total LDV gasoline use in 2000) and whether the state was a “yes”(1) or “no”(0). The result of this characterization is that 8 of the 11 regions are ranked “Yes” and 3 “No.”

4. For **natural gas used in both centralized and distributed production**, we used both state natural gas reserve estimates and the residential use of natural gas as indicators of a state’s potential use of natural gas to produce H_2 (EIA 2003a, EIA 2002). It is assumed that, for natural gas to be used extensively in a state to produce H_2, an extensive natural gas distribution system will be required to deliver the natural gas to stations. It is also assumed that the relative level of natural gas for residential energy indicates the extent of the natural gas distribution system in a state. If a state does not have such an extensive system, it can overcome the current lack of local natural gas distribution only if it has extensive natural gas reserves.

   Thus, states were classified into “a,” “b,” “c,” or “d” categories similar to those used for coal and biomass, on the basis of EIA’s estimates of natural gas reserves. States were also classified into those categories on the basis of EIA data showing the current share of residential energy use provided by natural gas. A state’s ultimate rating is the highest of the two ratings (i.e., if is “a” for reserves, but “c” for residential energy use [e.g., Texas], the state received an “a” rating).

   We then used a weighted average to characterize a region’s propensity to use natural gas. The weighted average accounted for each state’s potential level of

H_2 (as estimated by its proportion of total LDV gasoline use in 2000) and that state's natural gas ranking. The result of this characterization is that 2 of the 11 regions are ranked "A," 6 "B," 2 "C," and 1 "D."

5. For **centralized electrolysis**, we assumed that up to a maximum of 5% of today's regional electricity sales could be used to produce H_2 throughout the time of the analysis (EIA 2003a). (The "electrolysis" referred to here makes use of electricity generated by existing power plants to produce H_2. Production was assumed to typically occur during off-peak periods, when electricity prices are lowest.)

6. For **distributed electrolysis,** we assume that electricity is available everywhere. Table 3.1 presents the state and regional characterizations for natural gas, coal, renewables (and biomass, wind, and solar separately), and nuclear fuel. Figures 3.1–3.7 illustrate the regional characterization of the resource availability of these fuels. Table 3.2 presents our assumption of the maximum volume of H_2 that can be generated via centralized electrolysis, presuming the use of lowest-cost electricity.

3.3 SHARE OF H_2 GENERATED BY DISTRIBUTED PRODUCTION BY RESOURCE FUEL

We begin our estimation of the resource fuels used to produce H_2 by estimating the amount of H_2 that will be produced at service stations. Essentially, we assume that distributed production will be the only H_2 production method possible for some of the more rural areas (i.e., non-metropolitan areas) of the United States. Thus, we first estimated how much distributed production would be required in these areas and assumed that centralized production (from a variety of resource fuels) would provide the remaining H_2 in the rest of the country.

As indicated in Section 2, we assume that FCVs will eventually be used throughout the United States to meet the same travel demands as are met by existing vehicles. We also assume that, initially, FCV travel in non-metropolitan areas will only be along interstates. We assume that in 2020, all that travel (5.3% on average per Table 2.4, with regional variation) will be fueled by H_2 produced at stations. Table 2.4 also presents an estimate of the amount of non-metropolitan travel by FCVs in 2030, 2040, and 2050 (14.2%, 23.7%, and 23.7%, respectively). We expect that a large proportion of that travel will have to be fueled by H_2 produced at service stations. What that proportion might be is debatable: we assume 75% in each of those years. Table 3.3 presents the results of these assumptions: the share of all H_2 production that is distributed production by region by year.

We only assumed that two resource fuels would be used for distributed production of H_2: natural gas and electricity. Natural gas is generally much less expensive to use than electricity,

TABLE 3.1 Regional H_2 Resource Fuel Characterizations

	Natural Gas Characterization	Coal Resources	Renewables Characterization	Biomass	Wind	Solar	Nuclear Characterization
NEW ENGLAND	**C**	**D**	**B**	**C**	**A**	**D**	**Yes**
Connecticut	c	d		d	c	d	Yes
Maine	d	d		c	b	d	No
Massachusetts	b	d		c	b	d	Yes
New Hampshire	d	d		c	b	d	Yes
Rhode Island	b	d		d	c	d	No
Vermont	d	d		c	a	d	Yes
MIDDLE ATLANTIC	**B**	**A**	**B**	**B**	**B**	**D**	**Yes**
New Jersey	a	d		d	c	d	Yes
New York	b	d		b	b	d	Yes
Pennsylvania	b	a		b	b	d	Yes
EAST NORTH CENTRAL	**A**	**A**	**A**	**A**	**B**	**D**	**Yes**
Illinois	a	a		a	c	d	Yes
Indiana	b	b		a	c	d	No
Michigan	a	c		b	b	d	Yes
Ohio	a	a		a	c	d	Yes
Wisconsin	b	d		b	c	d	Yes
WEST NORTH CENTRAL	**B**	**B**	**A**	**A**	**A**	**B**	**Yes**
Iowa	b	b		a	a	c	Yes
Kansas	b	c		a	a	b	Yes
Minnesota	b	d		a	a	d	Yes
Missouri	b	b		a	c	c	Yes
Nebraska	b	d		a	a	b	Yes
North Dakota	c	b		a	a	c	No
South Dakota	c	c		a	a	c	No
SOUTH ATLANTIC	**C**	**A**	**A**	**A**	**B**	**C**	**Yes**
Delaware	c	d		d	d	d	No
DC	a	d		d	d	d	No
Florida	c	d		b	d	c	Yes
Georgia	c	c		a	d	c	Yes
Maryland	c	c		c	c	d	Yes
North Carolina	d	c		b	c	c	Yes
South Carolina	d	d		b	d	c	Yes
Virginia	b	b		b	c	d	Yes
West Virginia	b	a		c	b	d	No
EAST SOUTH CENTRAL	**B**	**A**	**B**	**A**	**C**	**C**	**Yes**
Alabama	b	b		a	d	c	Yes
Kentucky	b	a		b	d	d	No
Mississippi	c	c		a	d	c	Yes
Tennessee	c	c		a	c	c	Yes
WEST SOUTH CENTRAL	**A**	**B**	**A**	**A**	**A**	**A**	**Yes**
Arkansas	b	c		b	c	c	Yes
Louisiana	b	c		b	d	c	Yes
Oklahoma	a	c		b	a	b	No
Texas	a	b		a	b	a	Yes
MOUNTAIN	**B**	**A**	**A**	**B**	**A**	**A**	**No**
Arizona	d	c		c	d	a	Yes
Colorado	a	b		c	a	a	No
Idaho	c	c		b	a	b	No
Montana	b	a		c	a	c	No
Nevada	c	d		d	b	a	No
New Mexico	a	b		c	b	a	No
Utah	a	b		d	b	a	No
Wyoming	a	a		c	a	b	No

TABLE 3.1 (Cont.)

	Natural Gas Characterization	Coal Resources	Renewables Characterization	Biomass	Wind	Solar	Nuclear Characterization
CONTIGUOUS PACIFIC	**B**	**C**	**A**	**B**	**A**	**A**	**Yes**
California	b	d		b	a	a	Yes
Oregon	c	c		b	a	b	No
Washington	c	c		b	a	c	Yes
ALASKA	**B**	**B**	**C**	**D**	**B**	**D**	**No**
Alaska	b	b		d	b	d	No
HAWAII	**D**	**D**	**A**	**B**	**A**	**A**	**No**
Hawaii	d	d		b	a	a	No

A = High resource availability for coal and renewables. For natural gas, natural gas consumption is substantial and thus presumably so is distribution system; B = Region can use these resources for a long time, although they must look to others as well; C = Region is likely to look for other alternatives; D = Low resource availability for coal and renewables. For natural gas, natural gas consumption is insignificant and thus presumably so is distribution system.

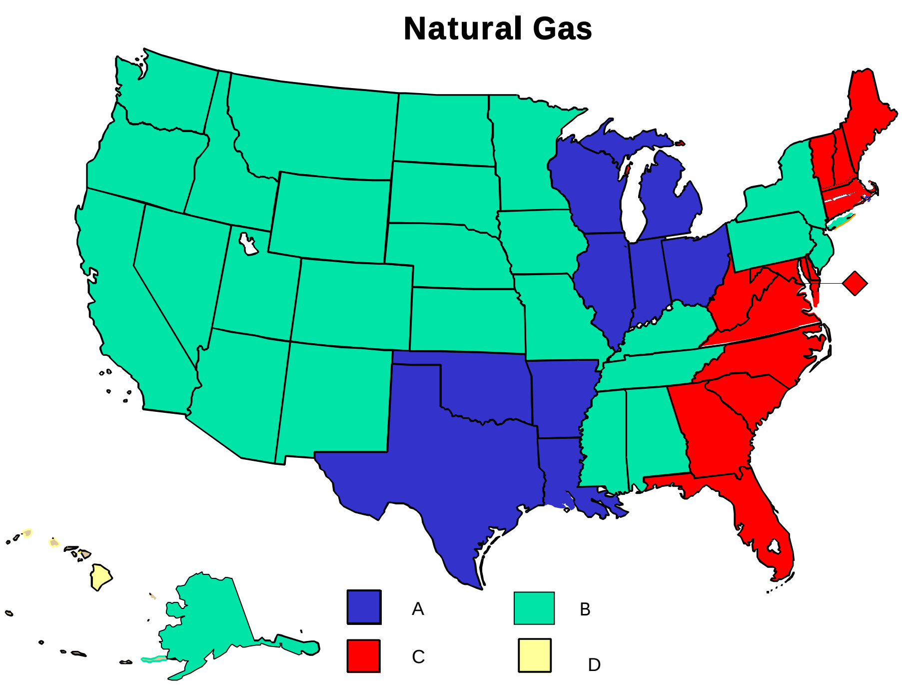

FIGURE 3.1 Regional Natural Gas Resource Characterization

Coal

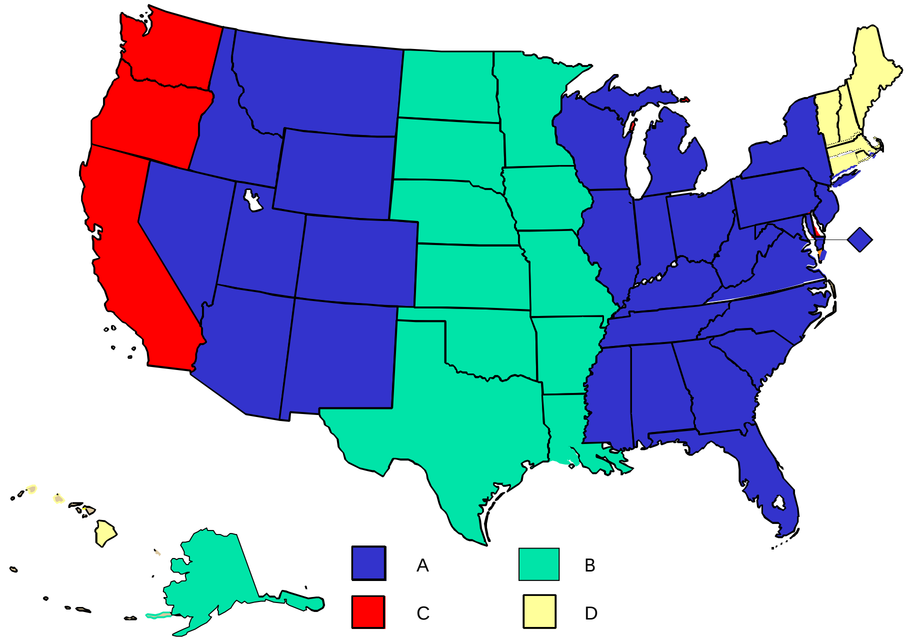

FIGURE 3.2 Regional Coal Resource Characterization

Nuclear

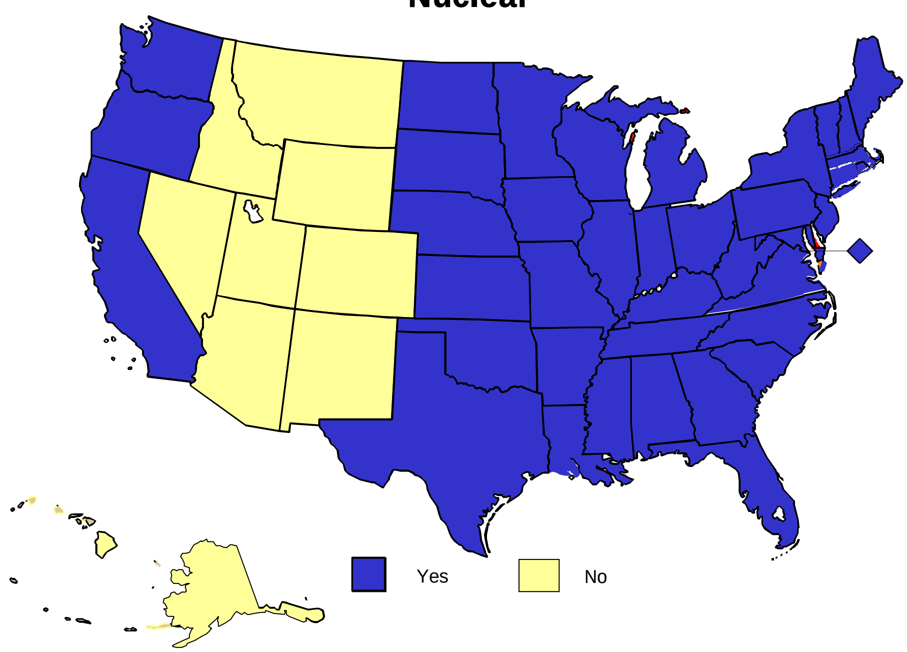

FIGURE 3.3 Regional Nuclear Resource Characterization

Renewables

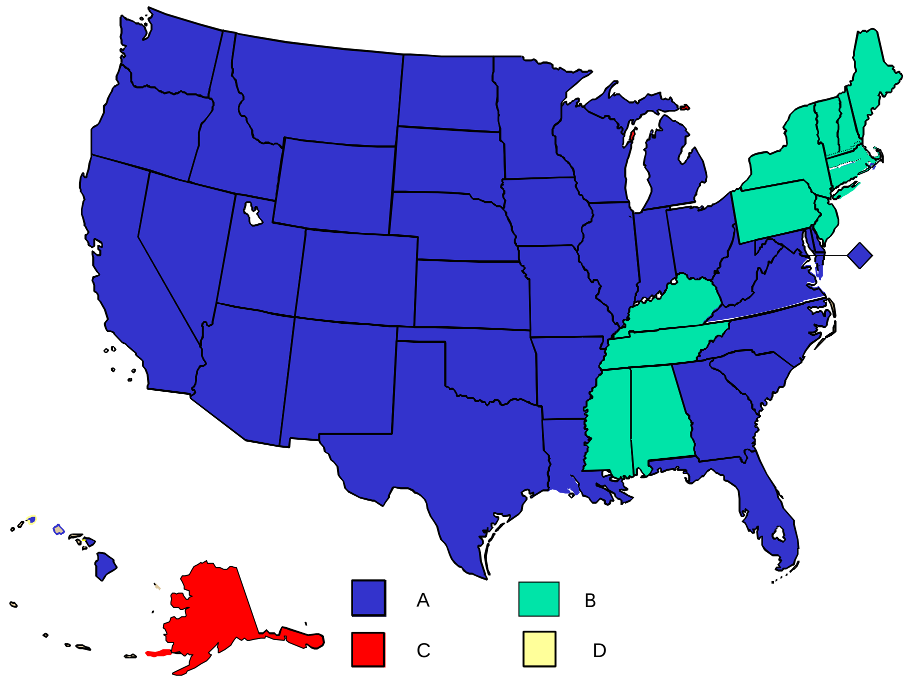

FIGURE 3.4 Regional Renewables Resource Characterization

Biomass

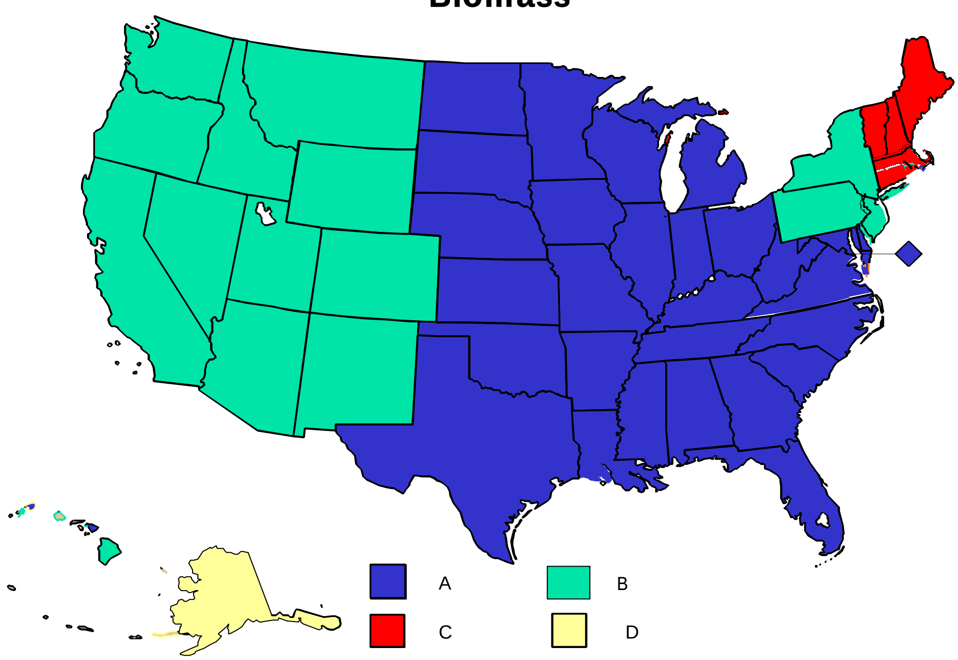

FIGURE 3.5 Regional Biomass Resource Characterization

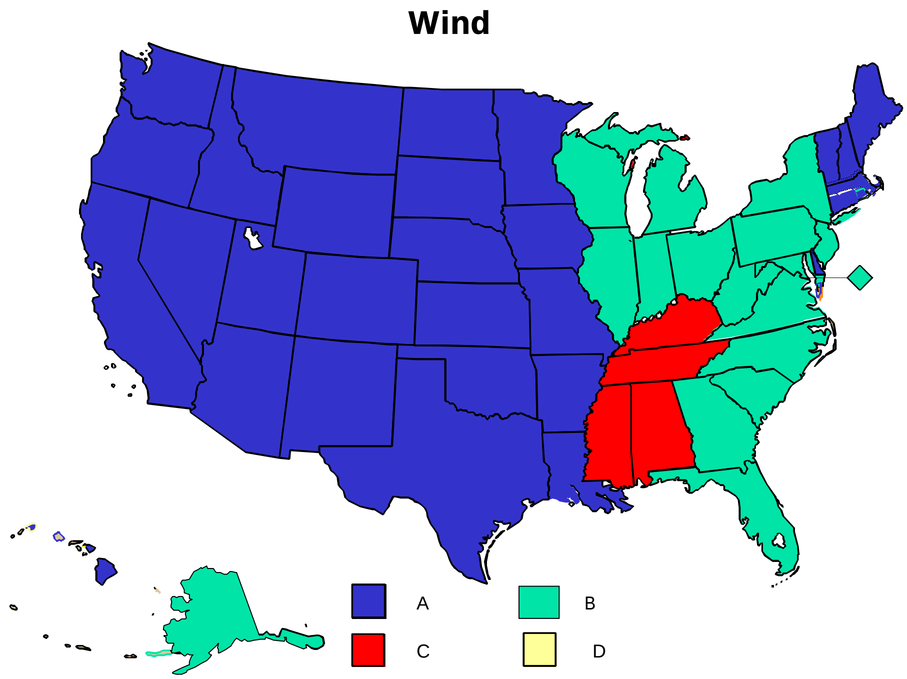

FIGURE 3.6 Regional Wind Resource Characterization

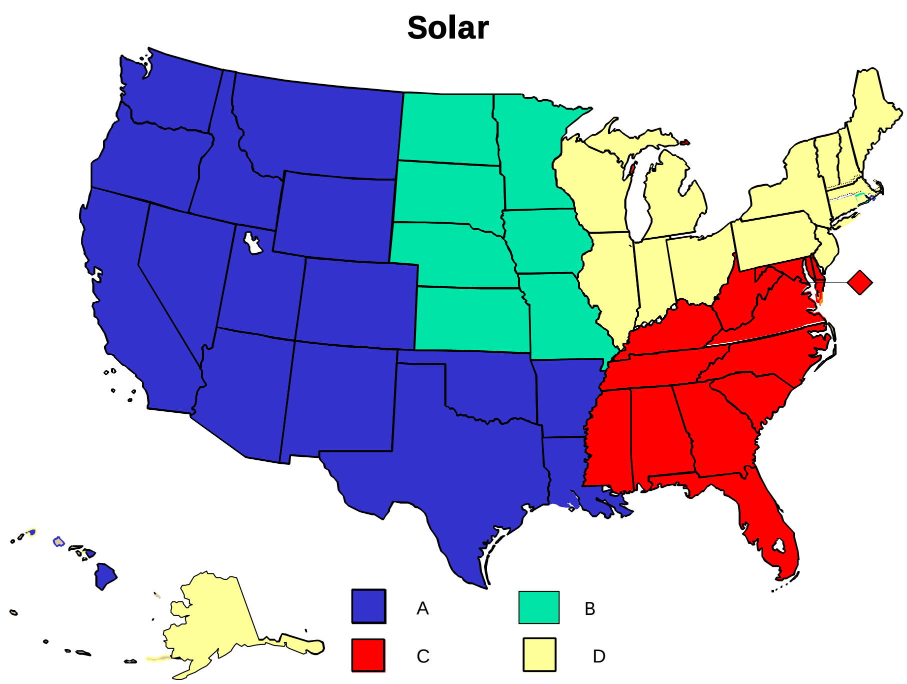

FIGURE 3.7 Regional Solar Resource Characterization

TABLE 3.2 Maximum H_2 That Can Be Generated for Centralized Electrolysis

U.S. Census Division	Maximum H_2 Generated from Centralized Electrolysis (Quads)
New England	0.027
Middle Atlantic	0.019
East North Central	0.055
West North Central	0.062
South Atlantic	0.070
East South Central	0.031
West South Central	0.062
Mountain	0.031
Pacific (contiguous states only)	0.047
Alaska	0.010
Pacific	0.001
United States	0.419

TABLE 3.3 Distributed Production Share of Total H_2 Production by Region

Region	2020 (%)	2030 (%)	2040 and 2050 (%)
New England	2.3	6.0	10.0
Middle Atlantic	2.7	5.3	8.8
East North Central	4.8	10.3	17.2
West North Central	8.7	19.4	32.3
South Atlantic	5.5	10.6	17.7
East South Central	7.8	19.7	32.8
West South Central	6.3	11.6	19.4
Mountain	10.3	15.9	26.5
Contiguous Pacific	2.0	3.4	5.6
Alaska	18.2	27.8	46.3
Hawaii	0.0	14.2	23.7
U.S. Total	5.3	10.7	17.8

but we assume that the use of natural gas will be phased out completely (unless H_2 demand is very low), which is consistent with the intent of the DOE program. Table 3.4 presents our assumptions about phasing out the use of natural gas for distributed production. The phaseout varies by each region's natural gas rating shown in Table 3.1.

The Regional H_2 Model is set up so that the user can modify our assumptions about the percentage of non-metropolitan travel that is served by distributed production. It is not set up to allow the use of distributed production in metropolitan areas in the early years of FCV use. Distributed production of H_2 in metropolitan areas may in fact occur, but we assume that metropolitan areas will turn to the less-expensive centrally produced H_2 alternative as quickly as possible.

3.4 CENTRALIZED PRODUCTION OF H_2 BY RESOURCE FUEL AND REGION

Once the volume of H_2 produced by distributed production is estimated, the total amount of H_2 produced centrally is set. The question then is what shares each resource fuel will contribute regionally.

We first estimate the volume of H_2 produced by centralized electrolysis. We assume that up to, but no more than, 5% of each region's current electricity generation can be used at power plants to produce H_2 relatively inexpensively and that this percentage will remain constant. But we further limit the volume generated by assuming that centralized electrolysis can be used to produce no more than 30% of the total H_2 required in a region, up to the maximum of 5%.

Next, using the resource characterizations presented in Section 3.2, we developed a number of "rules" or guiding assumptions that would allocate resources for centralized production of H_2 across regions, time, and demand levels. (All of these rules can be changed in the model — some more easily than others.) The rules are as follows:

1. For natural gas, we assume that it will be phased out completely by 2050, unless there is very low H_2 demand. Specifically, we assume:

    a. If total U.S. H_2 demand is less than 0.5 Quads in any year, only natural gas and centralized electrolysis will be used (unless a region is rated a "D" on

TABLE 3.4 Natural Gas Share of Distributed H_2 Production

Region's Natural Gas Rating	2010 Share (%)	2020 Share (%)	2030 Share (%)	2040 Share (%)	2050 Share (%)
A	80	80	50	20	0
B	65	65	40	15	0
C	50	50	25	0	0
D	0	0	0	0	0

natural gas, in which case only centralized electrolysis is used). (In the GYOW scenario, this demand level is reached by 2024, when approximately 15 million vehicles are on the road.)

b. If total U.S. H_2 demand is greater than 0.5 Quads, then the assumed maximum use of natural gas in a region is as shown in Table 3.5.

2. For thermochemical water splitting using advanced high-temperature nuclear reactors, we assume that this technology will not be in use until 2030 and that its national use will be approximately 20% by 2050. Specifically, we assume that it will provide 1% of the H_2 demand in 2030, 8% in 2040, and 20% in 2050 in regions that have nuclear power and that are rated highly ("A") either for coal or renewables. If a region has nuclear power, but is not rated highly for coal or renewables, it may use 25% more nuclear power than average.

3. The model calculates the percentage of H_2 produced from natural gas use and thermochemical water splitting via nuclear reactors first for each region. Coal and renewables as a whole split the difference, but according to the assumptions stated in Table 3.6.

4. Because the cost of H_2 produced from the individual renewable resources will vary, we also developed estimates of the composition of the regional renewable resource estimates developed above — in other words, what percentage will be produced from biomass, wind, and solar technologies. Estimating these variables is difficult to do on a resource basis alone. Even if a region received an "A" rating for solar and "Bs" for wind and biomass, we should not necessarily assume that "solar" would be more extensively used in that region to produce H_2 than the other two resources.

TABLE 3.5 Percent of H_2 Produced Centrally from Natural Gas where National Demand for H_2 > 0.5 Quads in Any Year[a]

Region's Natural Gas Rating	Percent Production, 2010	Percent Production, 2020	Percent Production, 2030	Percent Production, 2040	Percent Production, 2050
A	95	80	40	20	0
B	90	70	30	15	0
C	80	60	20	0	0
D	0	0	0	0	0

[a] Natural gas is also used at lower H_2 demand levels, but it then is one of only two options for producing H_2 centrally (see Section 3.4).

Table 3.6 Coal and Renewables Shares once Natural Gas and Nuclear Shares Are Estimated

Coal Rating	Renewables Rating	Coal Share (%)	Renewables Share (%)
A	A	50	50
	B	62.5	37.5
	C	75	25
B	A	37.5	62.5
	B	50	50
	C	62.5	37.5
C	A	25	75
	B	37.5	62.5
	C	50	50
D[a]	A/B/C	0	100

[a] There are no regions that are "D" in both coal and renewables.

Therefore, we turned to the EIA's AEO 2003, which contains projections of the volume of renewables by type used in electricity generation and end-use sector energy to 2025 by electricity market module (EMM) regions (EIA 2003a). The EMM regions are not the same as the U.S. Census Divisions. Still, we used the projections for the EMM regions to develop estimates of renewables use by type (on a percentage basis) in U.S. Census Divisions in 2025 (see Table 3.7). We then used these regional percentage estimates throughout the entire period of this analysis. Again, these percentage estimates are applied to the total renewables percent determined as discussed in "rule 3" above.

3.5 FINAL H_2 PRODUCTION ESTIMATES BY REGION FOR THE GYOW SCENARIO

The distributed and centralized production estimates were then combined, all on a regional basis. The final estimates for the United States are shown in Table 3.8 and Figure 3.8. Table 3.9 presents the percentage of each resource used to produce H_2 in each region by year. Figure 3.9 presents the regional results for 2050.

TABLE 3.7 Biomass, Wind, and Solar Shares of Renewables

U.S. Census Division	Biomass Share (%)	Wind Share (%)	Solar Share (%)
New England	82.8	14.6	2.6
Middle Atlantic	86.4	12.1	1.5
East North Central	85.2	14.1	0.7
West North Central	63.5	33.8	2.7
South Atlantic	92.8	5.1	2.1
East South Central	91.1	6.3	2.6
West South Central	38.1	58.7	3.2
Mountain	15.6	78.8	5.6
Pacific (contiguous states only)	29.7	63.7	6.6
Alaska	66.5	30.4	3.1
Pacific	66.5	30.4	3.1

TABLE 3.8 Final Estimate of H_2 Production in the United States for GYOW Scenario

	Distributed Production (Quads)		Centralized Production (Quads)							
Year	Distributed Natural Gas	Distributed Electrolysis	Electrolysis	Natural Gas	Coal	Biomass	Wind	Solar	Nuclear	Total
2010	0.00	0.00	0.000032	0.000073	0.000000	0.000000	0.000000	0.000000	0.000000	0.000105
2020	0.004	0.002	0.035	0.075	0.000	0.000	0.000	0.000	0.000	0.116
2030	0.085	0.132	0.396	0.438	0.437	0.396	0.150	0.018	0.014	2.065
2040	0.104	0.700	0.412	0.423	1.161	1.076	0.403	0.049	0.257	4.585
2050	0.000	0.996	0.412	0.000	1.501	1.354	0.535	0.063	0.812	5.673

	Distributed Production (%)		Centralized Production (%)							
Year	Distributed Natural Gas	Distributed Electrolysis	Electrolysis	Natural Gas	Coal	Biomass	Wind	Solar	Nuclear	Total
2010	0.0	0.0	30.0	69.8	0.0	0.1	0.1	0.0	0.0	100.0
2020	3.4	1.8	30.0	64.6	0.0	0.1	0.1	0.0	0.0	100.0
2030	4.1	6.4	19.2	21.2	21.1	19.2	7.2	0.9	0.7	100.0
2040	2.3	15.3	9.0	9.2	25.3	23.5	8.8	1.1	5.6	100.0
2050	0.0	17.6	7.3	0.0	26.5	23.9	9.4	1.1	14.3	100.0

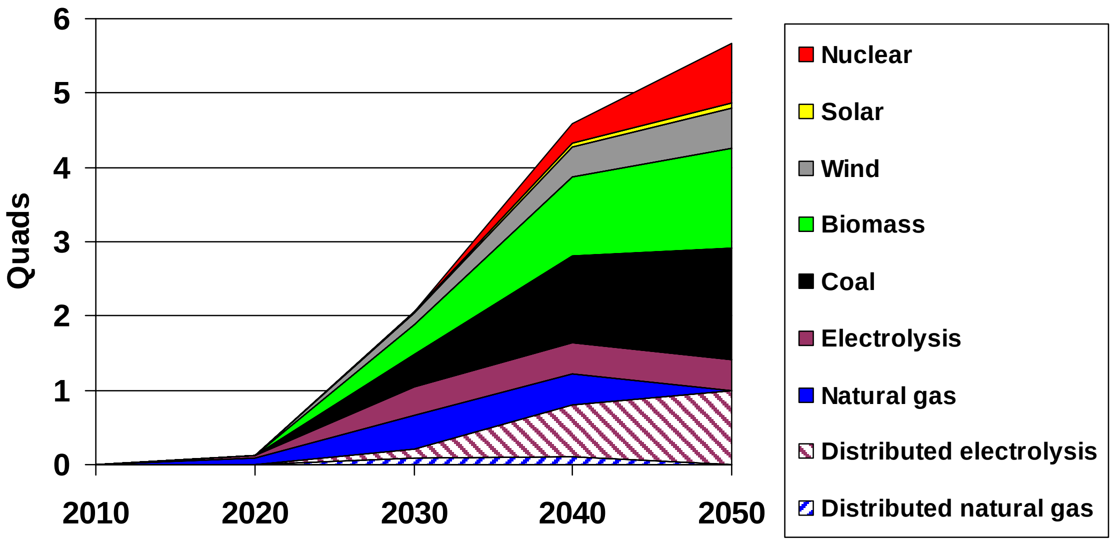

FIGURE 3.8 Resource Fuels Used to Produce H_2 in GYOW: United States

TABLE 3.9 Source of H_2 in GYOW Scenario by Region

		Distributed Production (%)		Centralized Production (%)							
Region		Natural Gas	Electrolysis	Electrolysis	Natural Gas	Coal	Biomass	Wind	Solar	Nuclear	Total Quads
NEW ENGLAND											
	2010	0.0	0.0	30.0	70.0	0.0	0.0	0.0	0.0	0.0	0.00001
	2020	1.1	1.1	30.0	67.7	0.0	0.0	0.0	0.0	0.0	0.006
	2030	1.5	4.5	27.3	13.3	0.0	43.5	7.7	1.3	0.8	0.10
	2040	0.0	10.1	12.3	0.0	0.0	57.9	10.2	1.8	7.8	0.22
	2050	0.0	10.1	9.9	0.0	0.0	49.7	8.8	1.5	20.0	0.27
MIDDLE ATLANTIC											
	2010	0.0	0.0	30.0	70.0	0.0	0.0	0.0	0.0	0.0	0.00001
	2020	1.8	1.0	30.0	67.3	0.0	0.0	0.0	0.0	0.0	0.013
	2030	2.1	3.2	8.6	25.8	37.1	19.2	2.7	0.3	0.9	0.23
	2040	1.3	7.5	3.9	13.1	42.0	21.8	3.1	0.4	7.0	0.51
	2050	0.0	8.8	3.1	0.0	44.0	22.8	3.2	0.4	17.6	0.64
EAST NORTH CENTRAL											
	2010	0.0	0.0	30.0	70.0	0.0	0.0	0.0	0.0	0.0	0.00002
	2020	3.9	1.0	30.0	65.2	0.0	0.0	0.0	0.0	0.0	0.018
	2030	5.2	5.2	17.0	29.1	21.4	18.3	3.0	0.2	0.7	0.33
	2040	3.4	13.7	7.7	15.0	27.1	23.0	3.8	0.2	6.0	0.73
	2050	0.0	17.2	6.2	0.0	30.7	26.1	4.3	0.2	15.3	0.90
WEST NORTH CENTRAL											
	2010	0.0	0.0	30.0	70.0	0.0	0.0	0.0	0.0	0.0	0.00001
	2020	5.6	3.0	30.0	61.3	0.0	0.0	0.0	0.0	0.0	0.009
	2030	7.8	11.6	30.0	15.2	13.1	13.9	7.4	0.6	0.5	0.16
	2040	4.8	27.4	17.6	7.5	14.5	15.3	8.1	0.7	4.0	0.35
	2050	0.0	32.3	14.2	0.0	16.0	17.0	9.0	0.7	10.7	0.44

TABLE 3.9 (Cont.)

Region		Distributed Production (%)		Centralized Production (%)							
		Natural Gas	Electrolysis	Electrolysis	Natural Gas	Coal	Biomass	Wind	Solar	Nuclear	Total Quads
SOUTH ATLANTIC											
	2010	0.0	0.0	30.0	70.0	0.0	0.0	0.0	0.0	0.0	0.00002
	2020	2.7	2.7	30.0	64.5	0.0	0.0	0.0	0.0	0.0	0.023
	2030	2.7	8.0	17.1	14.5	28.6	26.5	1.5	0.6	0.7	0.41
	2040	0.0	17.7	7.7	0.0	34.3	31.9	1.8	0.7	6.0	0.91
	2050	0.0	17.7	6.2	0.0	30.4	28.2	1.6	0.6	15.2	1.13
EAST SOUTH CENTRAL											
	2010	0.0	0.0	30.0	70.0	0.0	0.0	0.0	0.0	0.0	0.00001
	2020	5.0	2.7	30.0	62.2	0.0	0.0	0.0	0.0	0.0	0.008
	2030	7.9	11.8	21.9	17.5	25.2	13.8	0.9	0.4	0.6	0.14
	2040	4.9	27.9	9.9	8.6	27.6	15.1	1.0	0.4	4.6	0.31
	2050	0.0	32.8	8.0	0.0	29.6	16.2	1.1	0.5	11.8	0.39
WEST SOUTH CENTRAL											
	2010	0.0	0.0	30.0	70.0	0.0	0.0	0.0	0.0	0.0	0.00001
	2020	5.0	1.3	30.0	63.7	0.0	0.0	0.0	0.0	0.0	0.014
	2030	5.8	5.8	24.8	25.4	14.1	21.3	1.5	0.6	0.6	0.25
	2040	3.9	15.5	11.2	13.9	18.7	28.5	2.0	0.8	5.6	0.56
	2050	0.0	19.4	9.0	0.0	21.5	32.6	2.2	0.9	14.3	0.69
MOUNTAIN											
	2010	0.0	0.0	30.0	70.0	0.0	0.0	0.0	0.0	0.0	0.00001
	2020	6.7	3.6	30.0	59.7	0.0	0.0	0.0	0.0	0.0	0.008
	2030	6.4	9.6	22.7	18.4	21.5	3.4	16.9	1.2	0.0	0.14
	2040	4.0	22.6	10.2	9.5	26.9	4.2	21.2	1.5	0.0	0.30
	2050	0.0	26.5	8.3	0.0	32.6	5.1	25.7	1.8	0.0	0.38
CONTIGUOUS PACIFIC											
	2010	0.0	0.0	30.0	70.0	0.0	0.0	0.0	0.0	0.0	0.00002
	2020	1.3	0.7	30.0	68.0	0.0	0.0	0.0	0.0	0.0	0.017
	2030	1.3	2.0	16.2	24.1	13.9	12.3	26.5	2.8	0.8	0.30
	2040	0.8	4.8	7.3	13.1	16.8	14.9	32.0	3.3	7.0	0.66
	2050	0.0	5.6	5.9	0.0	17.7	15.8	33.8	3.5	17.7	0.81
ALASKA											
	2010	0.0	0.0	30.0	70.0	0.0	0.0	0.0	0.0	0.0	0.00000
	2020	11.8	6.4	30.0	51.8	0.0	0.0	0.0	0.0	0.0	0.000
	2030	11.1	16.7	30.0	12.7	18.5	7.4	3.4	0.3	0.0	0.00
	2040	6.9	39.4	30.0	3.6	12.6	5.0	2.3	0.2	0.0	0.01
	2050	0.0	46.3	30.0	0.0	14.8	5.9	2.7	0.3	0.0	0.01
HAWAII											
	2010	0.0	0.0	30.0	0.0	0.0	46.5	21.3	2.2	0.0	0.00000
	2020	0.0	0.0	30.0	0.0	0.0	46.5	21.3	2.2	0.0	0.000
	2030	0.0	14.2	19.3	0.0	0.0	44.1	20.2	2.1	0.0	0.01
	2040	0.0	23.7	8.7	0.0	0.0	44.9	20.5	2.1	0.0	0.01
	2050	0.0	23.7	7.0	0.0	0.0	46.0	21.0	2.2	0.0	0.02

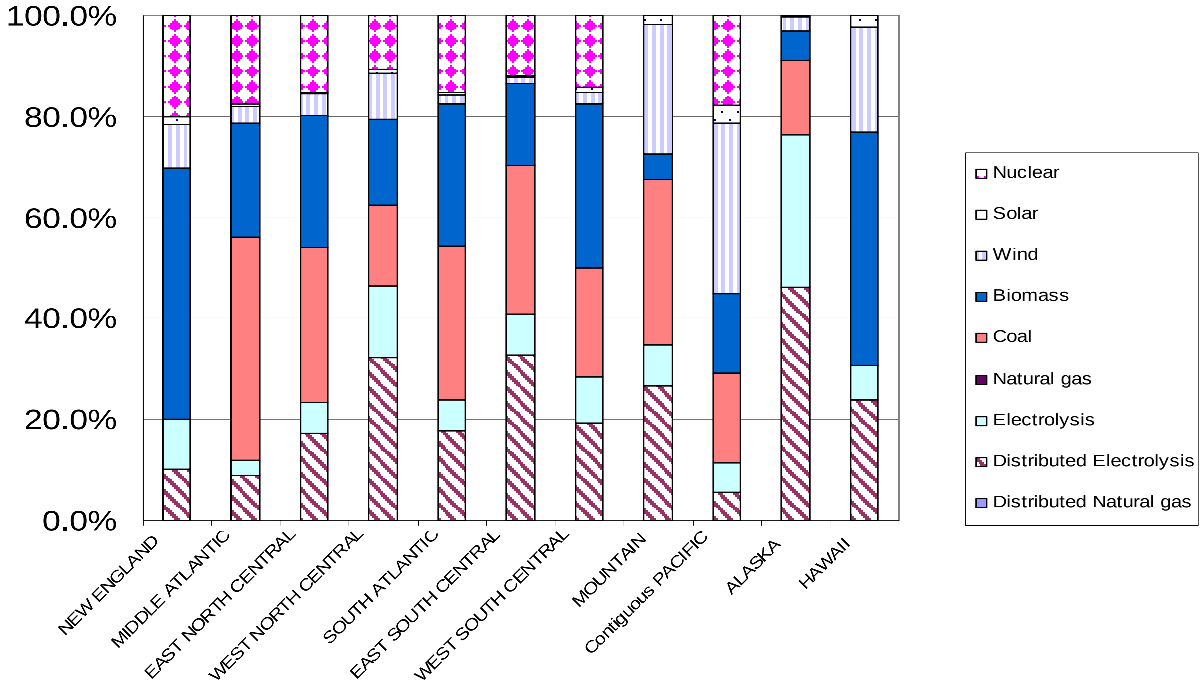

FIGURE 3.9 Source of H_2 in 2050 in GYOW Scenario by Region

4 HYDROGEN COST

4.1 OVERVIEW

In this section, we discuss how we developed H_2 cost estimates by region and over time for the GYOW scenario. Several general comments need to be made before discussing the details of the analysis.

1. Our cost estimates are just that: cost estimates. They are not price estimates, which are market-driven. Our cost estimates implicitly include some profit (i.e., capital costs include an expected rate of return). However, mark-up for retail profit on the sale of H_2 is not included. Finally, taxes are not included.

2. The principal source used to generate the cost estimates is a report by SFA Pacific (SFA), Inc. (2002). This reference was specifically used to develop estimates for the production of H_2 from the following technologies:

   - Steam reforming of natural gas or steam methane reforming (SMR),
   - Coal gasification,
   - Electrolysis,
   - Biomass gasification, and
   - Distributed production technologies (natural gas reforming and electrolysis in volumes compatible with demand at refilling stations in non-metropolitan locations).

3. Energy cost projections to 2025 for electricity, coal, and natural gas used in both the centralized and distributed production cost analysis are from EIA's AEO 2003 documentation (EIA 2003a). (AEO price projections are treated as costs in the production of H_2.) The 2020 to 2025 cost trends were extrapolated to 2050. AEO national average energy costs and extrapolations are summarized in Table 4.1. However, it is AEO's regional cost projections (and extrapolations from them consistent with the extrapolations shown in Table 4.1) that are used in this analysis.

4. Biomass resource costs were derived from biomass supply curves developed by ORNL and available by state (ORNL 2003). Regional estimates were calculated by weighting the state-level volume and price estimates. (The ORNL price estimates are treated as costs in the production of H_2.) The regional biomass resource estimates thus calculated are presented in Table 4.2.

TABLE 4.1 Costs of Input Energy (Natural Gas, Coal, and Electricity) to Produce Hydrogen, National Averages

Sector and Source	2000	2010	2020	2025	2030	2040	2050	Comments
Natural Gas Price, \$/mmBTU	5.59	5.03	5.35	5.60	5.92	6.57	7.23	Extrapolated from 2021–2025
Coal Price, \$/mmBTU	1.24	1.18	1.13	1.12	1.10	1.08	1.06	Extrapolated from 2021–2025
Coal Price Used for H_2 Cost Model, \$/mmBTU	1.24	1.18	1.13	1.13	1.13	1.13	1.13	Held constant after 2020
Electricity Price, \$/kwh	0.069	0.063	0.066	.067	0.069	0.071	0.073	Extrapolated from 2021–2025

TABLE 4.2 Costs of Input Energy (Biomass) to Produce Hydrogen[a]

Region	Median Price (\$/dry ton) in 2010	Median Price (\$/dry ton) in 2050
New England	30.03	23.78
Middle Atlantic	31.53	30.02
East North Central	29.99	26.84
West North Central	29.85	24.75
South Atlantic	27.97	24.25
East South Central	28.57	25.68
West South Central	30.55	25.88
Mountain	31.01	24.38
Pacific (contiguous states only)	29.08	23.03
Alaska	NA (assume Pacific)	
Pacific	NA (assume Pacific)	

[a] Median prices gradually decrease from 2010 to 2050 values.

We assume that these estimates apply to 2010 and are gradually lowered over time by as much as 20% by 2050, although there are regional variations. The 2050 estimates are also presented in Table 4.2.

5. Because the volume of H_2 produced and moved affects final costs and because the Regional H_2 Model was designed to allow alternative demand levels to be input, our cost estimates are generally developed for the President's Hydrogen Fuel Initiative scenario (100% penetration of FCVs). They are then input to the Regional H_2 Model, in which the demand level of any given scenario determines the costs finally estimated. The only exception is that the cost

estimates for distributed production were developed for the GYOW scenario. For demand levels higher than those of GYOW, the model assumes the distributed production cost estimates of the GYOW scenario.

6. Although we disaggregated the Pacific region into three regions (Contiguous Pacific, Alaska, and Hawaii) for H_2 demand and production estimates, we generally only developed cost estimates for the Contiguous Pacific region and used those costs for Alaska and Hawaii. However, there are exceptions (e.g., distributed production of H_2 using natural gas in Alaska).

7. Finally, our cost estimates are derived from several sources. We characterize our final cost estimates as being in 2001 dollars.

4.2 CENTRALIZED HYDROGEN PRODUCTION COST ESTIMATES

4.2.1 Production Technology

The cost analysis for each centralized production technology is based on a benchmark capacity of 150,000 kg/day, as utilized by SFA (SFA Pacific, Inc. 2002). SFA presented cost elements that would allow the costs for plants of various sizes to be estimated, but we chose to assume the same plant size for all centralized production technologies.

We assumed process efficiency improvements for all technologies. Initial values used were from the SFA report, improving toward U.S. DOE H_2 program efficiency goals for various technologies during the analysis period (DOE 2003). Principal process cost elements for one technology option — coal gasification — are listed below. These are representative of the approach used by SFA Pacific.

- Coal handling and preparation,
- Coal gasifiers (Texaco process),
- Air separators,
- CO_2 removal,
- Sulfur recovery,
- H_2 refrigeration for liquefaction,
- H_2 gas storage, and
- H_2 dispensing.

In addition to these sub-processes, indirect costs were considered by SFA Pacific — these are listed as percentage multipliers:

- General facilities,
- Engineering and permitting,
- Contingencies, and
- Working capital.

Estimates of the cost to produce H_2 include a capital amortization factor (18% of total capital) and operating cost allowance. The production of H_2 is capital cost intensive, but the capital costs vary by a factor of four or more among the technologies, which results in the numerical multipliers causing a large variation in the indirect cost elements of the alternative technologies. We altered the SFA multipliers to make the capital cost values of the indirect costs similar among the technologies.

Similar breakdowns in cost elements by major process sub-element are used to determine the cost of producing H_2 through steam reforming of natural gas, biomass gasification, and electrolysis. Our analysis allowed for limited reductions in the cost of process equipment. The cost models include CO_2 separation, but they do not include sequestration. For coal, a 20% multiplier was applied to the derived costs to account for carbon sequestration. Process characteristics are summarized in Table 4.3.

The final production cost estimates for each region for natural gas, coal, and biomass are presented in Appendix A (Tables A.1–A.3). Table A.4 presents the cost of producing H_2 centrally from electrolysis. This cost is assumed to be the same for all regions. The Regional H_2 Model can accommodate the input of alternative regional estimates. We did not have time and/or satisfactory production process characterization to develop cost estimates for H_2 production from wind, solar, and nuclear sources. As placeholders, we assumed that the cost of wind energy for H_2 production in each region was 90% that of the region's biomass cost, the cost of solar energy for H_2 production was 110% of the region's biomass cost, and that the cost of nuclear energy for H_2 production would be the same as that of biomass. These placeholders can be updated.

4.2.2 Delivery and Dispensing Costs: National Averages

SFA developed cost estimates for the delivery of H_2 provided by liquefied (refrigerated) tanker, pressurized tank (tube trailer), and pipeline (SFA Pacific, Inc., 2002). SFA's estimates are presented in Table 4.4. The SFA estimates are based on assumptions about (1) pipeline construction cost and length and (2) numbers of tube and refrigerated trailers. The report indicates that these assumptions were generated on the basis of regional conditions in the northeastern United States. However, no variation was applied to reflect other regional conditions (e.g., differences in transport differences or construction cost).

In our analysis, we assumed that only liquefied H_2 tankers and pipelines would be used to deliver H_2. We assumed that liquefied H_2 tankers would be used initially (or for very low demand), and then, as production volume grows, a shift would occur from liquefied H_2 tanker to pipeline. This assumption applies to all centralized production technologies except natural gas, because the use of natural gas is eventually phased out. Hydrogen produced from centralized production plants using natural gas is assumed to be delivered by liquefied H_2 tanker.

TABLE 4.3 Process Characteristics Summary

- **Air Separation Unit (used for all gasifiers)**

The air separation unit creates oxygen from the air. The amount of oxygen needed depends upon the feedstock.

Biomass:	0.8 tons O_2 per ton of biomass (dry basis), 0.37 kWh/kg O_2
Coal and Refinery Residue:	1.0 tons of O_2 per ton of coal (dry basis), 0.40 kWh/kg O_2
Petroleum Coke:	1.05 tons O_2 per ton of dry feed, 0.40 kWh/kg O_2

- **Biomass Gasifier:** All biomass gasifiers are assumed to consume 15% of the input biomass to dry the remaining 85% for further processing. The gasifier then converts the raw, dry biomass to synthesis gas (a mixture of carbon monoxide and hydrogen). All biomass gasifiers are assumed to operate at 51% throughput efficiency, increasing to 61% by 2050 (fuel input to syngas output, LHV basis, not counting electric inputs).

- **Coal Gasifier:** All coal gasifiers are assumed to operate at 64% throughput efficiency (dry coal to syngas, LHV, not counting electric inputs).

CO Shift Reactors: All of the CO shift reactors act to convert the CO fraction produced in the gasifier to hydrogen and CO_2. All operate at approximately the same throughput efficiency (exclusive of electric input).

Energy Resource	Shift Reactor Throughput Efficiency (%) (not including electricity use)
• Biomass	89.4
• Refinery Residue	88.8
• Coal	87.9
• Petroleum Coke	87.3

Electrolysis: All electrolysis processes are assumed to operate at a 60% increasing to 75% electricity-to-hydrogen efficiency ([LHV] basis) and to produce by-product oxygen at a mass rate of 8:1 to hydrogen.

Reforming: Steam methane reforming is used to produce hydrogen directly from natural gas at a throughput efficiency of 78% increasing to 80%, exclusive of electric inputs.

Hydrogen Compression: In most cases, it is necessary to compress the hydrogen produced in the electrolyzers, reformers, and shift reactors so that it can be efficiently transported.

Process	Discharge Pressure (atmospheres [atm])
Electrolysis	10
Steam-Methane Reformer	30
Biomass Gasification	30
Coal and Coke Gasification	75
Petroleum Residue Gasification	80

Transport Mode	Pressure (atm)
Pipeline	75
Tube Truck	215

TABLE 4.4 H_2 Delivery and Dispensing Costs ($/GGE)

	Pipeline		Liquid Tanker		Tube Trailer	
Item	Delivery	Dispensing	Delivery	Dispensing	Delivery	Dispensing
SFA	2.73	0.99	0.17	1.18	1.94	0.93
Regional H_2 Model						
2010	NA	NA	0.15	1.13	Not estimated separately	
2020	1.57	0.83	0.15	0.91	Not estimated separately	
2030	0.40	0.72	0.15	0.86	Not estimated separately	
2040	0.14	0.61	0.15	0.72	Not estimated separately	
2050	0.12	0.44	0.15	0.52	Not estimated separately	

We reduced the delivery and dispensing cost of both pathways, assuming technological improvement over time. For pipelines, we also reduced SFA's estimates to account for the following:

- The assumed SFA Pacific transport distance of 600 km and 18% capital charges appeared high.

- As production volume grows, it was assumed that capital costs for old pipelines would be amortized, existing lines would be converted, and transport distances would decline as shipments increased. Therefore, transport and dispensing cost on a per-unit basis decreases with time.

Our national average delivery and dispensing cost estimates are also presented in Table 4.4. We hold the dispensing costs constant across regions.

4.2.3 Regional Delivery Costs: Pipelines

Once we developed the national average costs for H_2 delivery, we developed estimates of regional variation in delivery costs. To estimate regional H_2 pipeline delivery costs, we first estimated the average pipeline length from centralized H_2 production plants in each region by weighting an assumed national average length of 250 miles by the number of Metropolitan Statistical Areas (MSAs) and Principal MSAs (PMSAs) per 10,000 mi^2 in a region. In effect, we assume that the greater the urban density of a region, the shorter the average pipeline length that needs to be constructed or converted. We then developed estimates of the cost of constructing these pipelines in each region and varied the costs by using known regional variations in construction costs and electricity prices (EIA 2003a, R.S. Means 2002). Ultimately, we derived a cost/GGE H_2 delivered for each region.

The East South Central region had the "average" cost/GGE H_2 delivered thus estimated. We then assumed that (1) the East South Central region's pipeline delivery costs are the same as the national average estimated above and shown in Table 4.4 and (2) the delivery costs for all of the other regions are variants of that cost, based on each region's cost/GGE H_2 delivered relative to the East South Central's cost/GGE H_2 delivered. The regional pipeline delivery costs thus estimated are presented in the Appendices.

The effect of land or right-of-way costs are not included in our estimates of pipeline delivery costs. Land costs vary significantly among the regions of the United States, and, in an absolute sense, such costs tend to be non-trivial. However, we examined land costs as a percentage of current pipeline costs and found that on a percentage basis, they are a minor part of pipeline cost (*Oil and Gas Journal* 1999, 2001, and 2003). Table 4.5 summarizes our findings. Costs for six years are shown: 1998–2003. On a percentage basis, land costs vary from 2.9% to 9.5% of total pipeline costs during this period. The average is 5.8%. On a per-mile basis, the *Oil and Gas Journal* (September 8, 2003) reports that for 2003, land cost is $58,619/mile compared to total project cost of $1,286,000/mile, or less than 5% of total pipeline costs (*Oil and Gas Journal* 2003).

Further, because the transition from petroleum/natural-gas-based fuels is anticipated to occur as a result of the reduced availability and escalated cost of these fuels, our scenario also anticipates the reduced use of existing oil and gas pipelines. Hence, we assume that the hydrogen energy supply industry will strive to use existing rights-of-way that have become available as a result of the emergence of spare pipeline capacity as the supply of natural and petroleum-based fuels diminishes.

On the basis of these premises, this study assumes that right-of-way costs will continue to be a minor component — less than 5% percent of total — of the cost of building pipelines to transport H_2. Therefore, we left right-of-way costs out of our analysis. We recognize, however, that the magnitude of the H_2 infrastructure that would need to be developed to support a sizeable FCV market penetration suggests that further analysis of total right-of way costs is warranted.

TABLE 4.5 Summary of *Oil and Gas Journal* Pipeline Right-of-Way Cost Investigations

Period	Total Cost ($)	Rights of Way and Damages ($)	Land Cost/ Total Cost (%)	Comments
2003	1,166,584,784	53,154,705	4.6%	OGJ, Sept. 8, 2003, p. 72. July 1, 02 to June 30, 03 period (typical)
2002	2,023,766,121	77,551,159	3.8%	OGJ, Sept. 8, 2003, p. 72.
2001	1,468,338,874	134,551,570	9.2%	OGJ, Sept. 3, 2001, p. 74.
2000	2,246,011,324	213,871,544	9.5%	OGJ, Sept. 3, 2001, p. 74.
1999	979,596,710	76,662,856	7.8%	OGJ, Aug. 23, 1999, p. 57.
1998	3,438,682,971	99,468,844	2.9%	OGJ, Aug. 23, 1999, p. 57; includes Canada.
Average			**5.8%**	

4.2.4 Regional Delivery Costs: Other

For H_2 delivery by truck, we used a process similar to that described above for pipelines to develop regional costs. As with pipelines, we estimated that average truck delivery distances would be shorter in regions with greater urban density. The regional truck delivery costs thus estimated are presented in the Appendices.

None of the above discussion applies to the delivery of H_2 produced by centralized electrolysis. Because we did not develop regional costs for producing H_2 by this method (as discussed in Section 4.2.1), we did not develop the associated regional delivery costs. Also, we used delivery costs for tube trailers (starting with SFA's estimates), although we meant to assume use of liquefied H_2 tankers, particularly in the early years. However, we have not changed these costs and present them in Table A-4.

4.3 DISTRIBUTED PRODUCTION

4.3.1 Station Volumes

The volume of H_2 produced at a station is one of the major variables in the cost of distributed production, particularly from natural gas. In Section 3.3, we estimated the total volume of H_2 that would be produced at stations in each region by year for the GYOW scenario. For our cost analysis, we need to estimate how many stations will be built to dispense that volume. The estimation method is explained below.

4.3.1.1 Year 2020

For distributed production at non-metropolitan area interstate stations in 2020 (which is the only distributed production we assume in that year), we first reviewed data available on several state web sites that indicated the distance between interchanges along interstates (largely, but not all, rural) in those states (Pennsylvania Turnpike 2003, Kansas Turnpike Authority 2003, and Ohio Turnpike 2003). We found the average or typical distance to be 30 miles. We assume that there is at least one fuel-dispensing station at each of these interchanges and that it serves traffic going in both directions along the interstate. From U.S. EPA VMT data by road type and supporting documentation, we were able to estimate the number of interstate miles in non-metropolitan counties (by county). We estimate that in 2002, there were approximately 21,000 miles of interstate roads in the United States in non-metropolitan counties. We developed these estimates by region. If we assume that there is a station on average every 30 miles, then there should be approximately 700 stations on non-metropolitan area interstates. We also developed these estimates by region.

For our H_2 cost analysis, we assumed that one-half of these stations would provide H_2 in 2020. Given these station totals (by region) and our estimates of the total volume of H_2 produced at stations in each region (see Table 3.9), we can then estimate average station volumes by region. The resulting range of station volumes across regions for the year 2020 is shown in Table 4.6.

4.3.1.2 Years 2030–2050

As indicated in Section 2, in the GYOW scenario, we assume that by 2040 FCVs will be able to, on average, complete all of the non-metropolitan area travel of today's vehicles. In other words, they are assumed to be able to travel throughout the United States without refueling limitations. For that to happen, we assume that H_2 eventually will be available at all service stations in non-metropolitan areas. We used the current number of gasoline stations in non-metropolitan areas as a first-cut estimate of the number needed to dispense H_2 in the future. There are at least two sets of estimates of the number of existing stations: we used the U.S. Economic Census data because only those data identify stations by county (U.S. Census Bureau 2000). For 2030, when FCV travel in non-metropolitan areas is still expanding, we assume that only 60% of those stations will provide H_2. The total number of H_2 stations in the United States in non-metropolitan areas thus estimated is presented in Table 4.6.

Not all of these stations will produce H_2 at the station. In Section 3.3, we assumed that 75% of the H_2 stations in non-metropolitan areas would provide H_2 via distributed production. Given these station totals (by region) and our estimates of the total volume of H_2 produced at stations in each region (see Table 3.9), we can then estimate average station volumes by region. The resulting range of station volumes across regions for the years 2030-2050 is shown in Table 4.6. We assume the volume dispensed at interstate stations is included in these estimates.

Table 4.6 Number of Non-Metropolitan Area Stations Producing H_2 at the Station and Volume/Month in the GYOW Scenario

Year	Total Number of H_2 Stations in Non-Metropolitan Areas	Number of H_2 Stations Producing H_2 in Non-Metropolitan Areas	Volume Dispensed per Month (GGE): U.S. Average	Volume Dispensed per Month (GGE): Regional Range
2010	NA	NA	NA	NA
2020	325	325	12,454	0–1,721
2030	23,952	17,974	8,065	7,031–10,283
2040	39,942	29,957	17,910	15,613–22,836
2050	39,942	29,957	22,161	19,319–28,255

NA = not applicable

4.3.2 Station Cost Analysis

The analysis of the cost of distributed production of H_2 is also based on one of the SFA models, with some changes and simplifications. The major differences from the centralized production models are summarized below:

- Energy costs are based on EIA commercial sector projections rather than industrial (EIA 2003a).

- Distribution costs are not separated because the production occurs at the dispensing point.

- Reformer efficiency was increased from 70% to 85% during the 2020–2050 time period. However, we have made no other technology improvement assumptions or financial assumptions that would significantly reduce cost during the analysis period.

- This equipment is expected to have a shorter lifetime and, hence, higher amortization factors than the central equipment.

The regional estimates of station volume discussed above were converted to number of refills per day (at approximately 4 GGE/refill). These estimates, in turn, were used to estimate reforming capacities and cost for H_2 produced at distributed stations employing natural gas reforming technology. The specific regional estimates can be found in the Appendix (Table A.5).

These same regional production volumes and refill requirements were used for the capacities of stations using electrolysis to produce H_2. Because of time constraints, we only estimated the costs for five regions in detail (see Table A.6). Subsequently, by examining regional differences in commercial electricity costs, we estimated the total cost of using electrolysis for the remaining four regions (see Table A.7).

Analysis of the distributed electrolysis results indicates that the per-GGE costs for electrolysis are relatively insensitive to station size. Indeed, a 10% increase in station size yields a cost reduction of only about a 1% electrolyzer per kilowatt. A 100% increase in size yields a cost reduction of only 7% per kilowatt. In contrast, modeling of the production of H_2 from natural gas showed that an increase in station size of 100% yields about a 16% reduction in unit costs. Note that we allowed electrolyzer efficiency to increase to 85% by 2040, on the basis of the DTI optimistic projection of up to 89% (Myers et al. 2003).

The biggest factor driving the production cost for electrolysis is the $2,000 per kilowatt baseline cost factor. (At least one other report has lower estimates. See a comparison of SFA's costs with those of DTI's in Appendix Table B.1.) Nearly 60% of the per-GGE cost is due to the electrolyzer capital cost, with commercial electricity costs in the 6–7¢/kWh range. If electricity cost were in the 2–3¢/kWh range, then about 80% of the per-GGE cost would be due to capital cost.

4.4 OBSERVATIONS ON H_2 PRODUCTION COST ESTIMATES

The commercialization of H_2 production and distribution systems is highly capital intensive. Therefore, there is limited sensitivity to process efficiency and input energy (feedstock) cost. For example, a doubling of the natural gas feedstock costs that we used would result in a 20–30% increase in delivered H_2 costs over time in the Mid-Atlantic region.

We have estimated substantial reductions over time in virtually all of our centralized production pathways. We have also estimated reductions in the distributed production of H_2, but there may be greater opportunities for cost reduction in distributed production by using electrolysis than we have estimated. As indicated above, comparisons of SFA's costs with those of DTI's are provided in Appendix Table B.1.

Finally, our cost estimates are generally higher than the cost goals of the U.S. DOE H_2 program.

4.5 FINAL DELIVERED H_2 COST ESTIMATES FOR THE GYOW SCENARIO

As indicated in Section 4.1, the cost estimates discussed above are tied to specific fuel volumes. Using these volume specific cost estimates, the Regional H_2 Model generates final cost estimates for any scenario of H_2 demand. Table 4.7 presents the final year-by-year, technology-by-technology, and region-by-region H_2 cost estimates of the GYOW scenario. The national estimates are summarized in Table 4.8 and Figure 4.1. Again, no taxes are included in the cost estimates.

As the tables and figure illustrate, the cost of producing, delivering, and dispensing H_2 declines over time for virtually all of the technologies. However, the increasing use of relatively expensive distributed H_2 production, particularly from electrolysis, to meet the needs of travel in non-metropolitan areas leads to an essentially stable average cost of H_2 of around \$3.70/GGE (see Figure 4.2) from 2020 to 2050. This figure also illustrates the very large difference that exists between the cost of H_2 in metropolitan and non-metropolitan areas: nearly \$5/GGE by 2050 (national average). Table 4.9 presents the metropolitan and non-metropolitan area costs by region.

Figure 4.3 illustrates the range in average costs across the country. By 2050, regional H_2 costs vary from \$2.97/GGE (contiguous Pacific) to \$6.65/GGE (Alaska). Alaska is unique. The next highest H_2 costs (between \$4.50 and \$4.82/GGE) are in the West North Central, Mountain, and Hawaii regions. In essence, excluding Alaska, we estimate a range of H_2 cost differentials across regions of nearly \$2/GGE by 2050. (The variation, excluding Alaska, is approximately \$1/GGE in 2020, \$1.20/GGE in 2030, and \$2/GGE in 2040.) This result — the potential for great regional variation in H_2 costs — is one of the main points that we wanted to illustrate with this analysis.

TABLE 4.7 Final Delivered H_2 Costs in GYOW by Region by Production Technology

Region	Year	Distributed Natural Gas $/GEG	Distributed Electrolysis $/GEG	Centralized Natural Gas $/GEG	Centralized Electrolysis $/GEG	Coal with Carbon Sequestration $/GEG	Biomass $/GEG	Wind $/GEG	Solar $/GEG	Nuclear $/GEG	Weighted Price $/GEG
NEW ENGLAND											
	2010	4.42	15.27	3.52	7.36	5.02	4.68	4.21	5.15	4.68	4.67
	2020	4.37	14.13	3.52	4.38	5.02	4.68	4.21	5.15	4.68	3.91
	2030	4.74	13.80	3.52	3.75	5.02	2.78	2.50	3.06	2.78	3.65
	2040	4.23	12.44	3.52	3.75	5.02	2.52	2.27	2.77	2.52	3.65
	2050	4.17	12.35	3.52	3.75	5.02	2.52	2.27	2.77	2.35	3.58
MIDDLE ATLANTIC											
	2010	4.26	11.30	3.46	4.38	4.63	4.53	4.07	4.98	4.68	3.73
	2020	4.07	11.75	3.46	4.38	4.63	4.53	4.07	4.98	4.68	3.82
	2030	4.52	11.32	3.41	3.75	2.64	2.67	2.40	2.94	2.78	3.25
	2040	4.01	9.91	3.41	3.75	2.34	2.44	2.19	2.68	2.52	3.15
	2050	3.90	9.54	3.45	3.75	2.34	2.44	2.19	2.68	2.35	3.04
EAST NORTH CENTRAL											
	2010	4.15	9.62	3.26	4.38	4.54	4.42	3.98	4.86	4.68	3.59
	2020	3.96	8.90	3.26	4.38	4.54	4.42	3.98	4.86	4.68	3.67
	2030	4.42	8.69	3.21	3.75	2.73	2.74	2.47	3.02	2.52	3.43
	2040	3.93	7.83	3.21	3.75	2.32	2.42	2.17	2.66	2.35	3.40
	2050	3.84	7.78	3.29	3.75	2.32	2.42	2.17	2.66	2.35	3.37
WEST NORTH CENTRAL											
	2010	4.13	10.08	3.54	7.36	4.72	4.62	4.16	5.08	4.68	4.69
	2020	4.24	10.17	3.47	4.38	4.72	4.62	4.16	5.08	4.68	3.99
	2030	4.56	9.94	3.47	3.75	3.67	3.72	3.35	4.09	2.78	4.44
	2040	4.12	9.00	3.47	3.75	3.67	3.72	3.35	4.09	2.52	5.09
	2050	4.11	8.99	3.54	3.75	2.63	2.75	2.48	3.03	2.35	4.82
SOUTH ATLANTIC											
	2010	4.34	11.30	3.21	4.38	4.63	4.41	3.97	4.85	4.68	3.56
	2020	3.92	9.32	3.21	4.38	4.63	4.41	3.97	4.85	4.68	3.75
	2030	4.56	9.54	3.12	3.75	2.73	2.67	2.41	2.94	2.52	3.53
	2040	4.03	8.68	3.25	3.75	2.36	2.38	2.15	2.62	2.35	3.59
	2050	3.89	8.68	3.25	3.75	2.36	2.38	2.15	2.62	2.35	3.57

TABLE 4.7 (Cont.)

Region	Year	Distributed Natural Gas $/GEG	Distributed Electrolysis $/GEG	Centralized Natural Gas $/GEG	Centralized Electrolysis $/GEG	Coal with Carbon Sequestration $/GEG	Biomass $/GEG	Wind $/GEG	Solar $/GEG	Nuclear $/GEG	Weighted Price $/GEG
EAST SOUTH CENTRAL											
	2010	4.27	10.23	3.25	7.36	4.58	4.43	3.98	4.87	4.68	4.48
	2020	3.97	9.47	3.21	4.38	4.58	4.43	3.98	4.87	4.68	3.77
	2030	4.55	9.24	3.12	3.75	2.81	2.80	2.52	3.08	2.78	3.97
	2040	4.01	8.33	3.12	3.75	2.81	2.80	2.52	3.08	2.52	4.51
	2050	3.88	8.28	3.25	3.75	2.36	2.43	2.18	2.67	2.35	4.42
WEST SOUTH CENTRAL											
	2010	4.11	12.37	3.30	7.36	4.60	4.51	4.06	4.96	4.68	4.51
	2020	4.00	11.45	3.26	4.38	4.60	4.51	4.06	4.96	4.68	3.73
	2030	4.41	11.18	3.21	3.75	2.93	2.98	2.68	3.27	2.78	3.78
	2040	3.90	10.07	3.21	3.75	2.41	2.53	2.28	2.79	2.52	3.96
	2050	3.79	10.01	3.30	3.75	2.41	2.53	2.28	2.79	2.35	4.04
MOUNTAIN											
	2010	4.09	10.84	3.72	7.36	4.99	4.88	4.39	5.36	4.68	4.81
	2020	4.42	10.37	2.42	4.38	4.99	4.88	4.39	5.36	4.68	3.43
	2030	4.31	9.63	2.47	3.75	4.58	4.62	4.16	5.08	4.68	4.40
	2040	3.93	8.70	2.47	3.75	4.58	4.62	4.16	5.08	4.68	5.12
	2050	3.96	8.67	3.72	3.75	2.96	3.08	2.77	3.39	4.68	4.51
CONTIGUOUS PACIFIC											
	2010	4.33	13.90	3.51	4.38	5.25	4.98	4.48	5.48	4.68	3.77
	2020	4.13	11.53	3.51	4.38	5.25	4.98	4.48	5.48	4.68	3.83
	2030	4.56	11.45	3.50	3.75	3.16	3.09	2.79	3.40	2.52	3.42
	2040	4.15	10.47	3.50	3.75	2.55	2.58	2.32	2.84	2.35	3.08
	2050	4.16	10.56	3.69	3.75	2.55	2.58	2.32	2.84	2.35	2.97
ALASKA											
	2010	4.33	13.90	3.69	7.36	5.25	4.98	4.48	5.48	4.68	4.79
	2020	5.89	11.53	3.51	4.38	5.25	4.98	4.48	5.48	4.68	4.56
	2030	4.54	11.45	3.50	3.75	3.16	3.09	2.79	3.40	4.68	4.90
	2040	4.13	10.47	3.51	3.40	3.16	3.09	2.79	3.40	4.68	6.18
	2050	4.15	10.56	3.69	3.40	3.16	3.09	2.79	3.40	4.68	6.65

TABLE 4.7 (Cont.)

Region	Year	Distributed Natural Gas $/GEG	Distributed Electrolysis $/GEG	Centralized Natural Gas $/GEG	Centralized Electrolysis $/GEG	Coal with Carbon Sequestration $/GEG	Biomass $/GEG	Wind $/GEG	Solar $/GEG	Nuclear $/GEG	Weighted Price $/GEG
HAWAII											
	2010	4.33	13.90	3.69	7.36	5.25	4.98	4.48	5.48	4.68	5.60
	2020	4.13	11.53	3.69	4.38	5.25	4.20	3.78	4.62	4.68	4.18
	2030	4.56	11.45	3.69	3.75	5.25	3.09	2.79	3.40	4.68	4.36
	2040	4.15	10.47	3.69	3.75	5.25	3.09	2.79	3.40	4.68	4.85
	2050	4.16	10.56	3.69	3.75	5.25	2.58	2.32	2.84	4.68	4.51

TABLE 4.8 Final Delivered H_2 Costs in GYOW: U.S. Summary by H_2 Production Technology

		H2 Cost ($/GGE)									
Year	GGE (billions)	Distributed Natural Gas	Distributed Electrolysis	Centralized Natural Gas	Centralized Electrolysis	Coal with Sequestration	Biomass	Wind	Solar	Nuclear	Total
2010	0.001	NA	NA	3.38	5.53	NA	4.98	4.48	5.48	NA	4.03
2020	0.93	4.09	10.17	3.28	4.38	NA	4.20	3.78	4.62	NA	3.76
2030	16.5	4.48	9.99	3.25	3.75	2.95	2.87	2.97	3.45	2.63	3.67
2040	36.7	3.98	9.02	3.26	3.75	2.62	2.57	2.67	3.07	2.42	3.77
2050	45.4	NA	8.96	NA	3.75	2.43	2.49	2.39	2.86	2.35	3.68

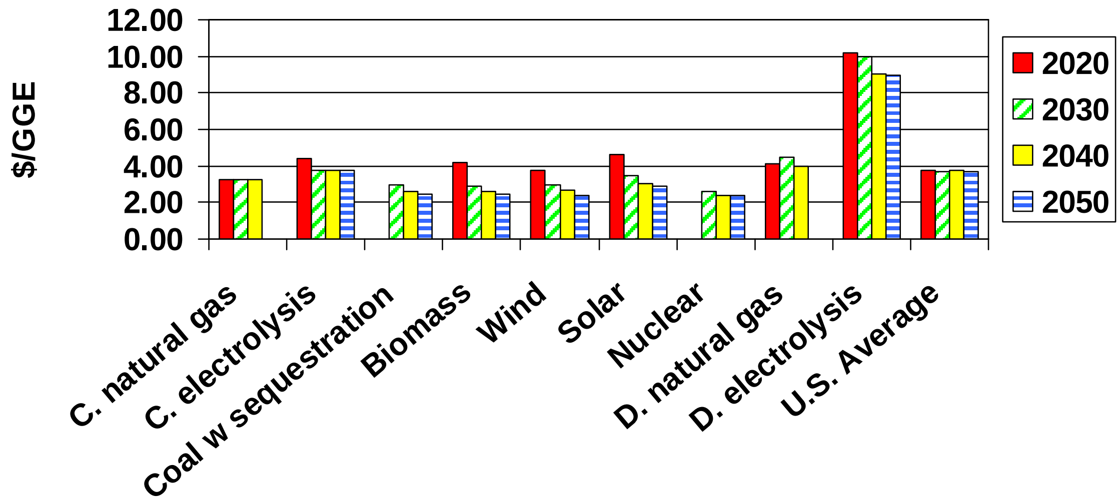

FIGURE 4.1 Final Delivered H_2 Cost in GYOW: U.S. Summary by H_2 Production Technology

4.6 SENSITIVITY ANALYSIS

There are many assumptions underlying our estimates. In Table 4.10, we show the impacts of varying just three of those assumptions related to distributed production. If we change our assumption that natural gas use for H_2 production will be phased out by 2050 to one in which it continues to be used for distributed production and in substantial amounts (65% of all distributed production), the average cost of H_2 in the United States by 2050 would fall from $3.68/GGE to $3.10/GGE by 2050. If, instead, our estimates of the cost of distributed production from electrolysis were modified to be more similar to those presented in Appendix B (in effect cutting our estimates almost in one-half), then the average cost of H_2 in the United States by 2050 would fall even further, to $2.89/GGE. Alternatively, if we assume that all non-metropolitan travel by FCVs is served by distributed production (instead of 75%), then the average cost of H_2 in the United States by 2050 would increase to $4.10/GGE. In sum, varying just these assumptions results in a swing of over $1/GGE of H_2 (national average).

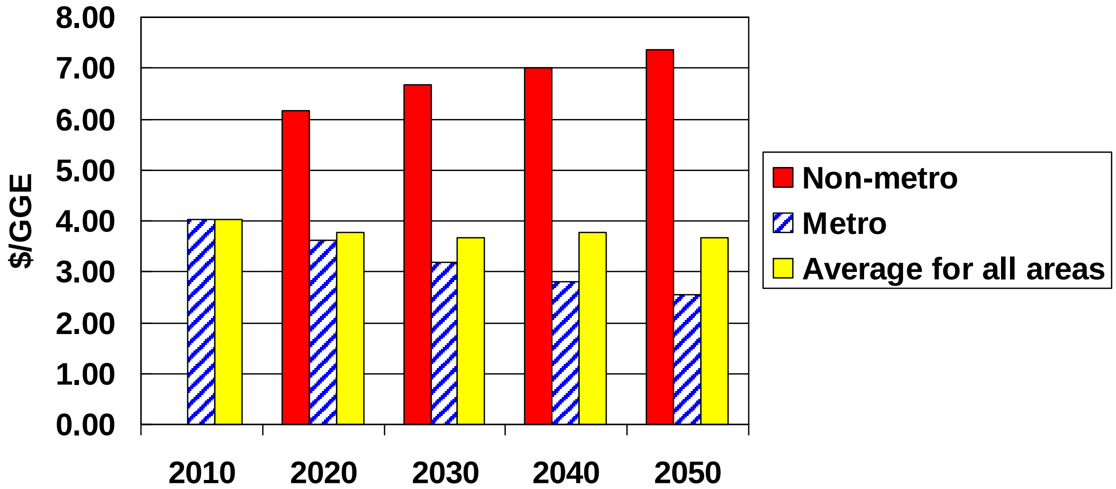

Figure 4.2 Final Delivered H_2 Cost in GYOW: U.S. Summary by Metropolitan versus Non-Metropolitan Areas

Finally, in Table 4.11, we present the impacts of varying these same three assumptions on H_2 costs in metropolitan and non-metropolitan areas. Where there is a difference of nearly $5/GGE in the cost of H_2 in metropolitan and non-metropolitan areas in the GYOW scenario by 2050, that cost difference is dramatically lowered to less than $2.50/GGE if natural gas continues to be used for distributed production and approximately $1.50/GGE if the cost of distributed production from electrolysis is reduced by 50%. The difference is increased if all non-metropolitan travel by FCVs is served by distributed production.

TABLE 4.9 Final Delivered H_2 Costs in GYOW by Region by Metropolitan and Non-Metropolitan Areas

		Non-Metro Areas				Metro Areas		
Region	Year	Distributed Production Total GEG	Centralized Production Total GEG	Total GEG	Weighted Cost ($/GGE)	Centralized Production Total GEG	Weighted Cost ($/GGE)	Total Weighted Cost ($/GGE)
NEW ENGLAND								
	2010	0	0	0	0.00	40,615	4.67	4.67
	2020	1,029,273	0	1,029,273	9.25	43,822,288	3.78	3.91
	2030	48,146,228	16,048,743	64,194,971	9.44	734,124,153	3.15	3.65
	2040	178,194,134	59,398,045	237,592,179	9.99	1,535,204,442	2.67	3.65
	2050	220,482,692	73,494,231	293,976,922	9.91	1,899,535,075	2.60	3.58
MIDDLE ATLANTIC								
	2010	0	0	0	0.00	94,167	3.73	3.73
	2020	2,844,985	0	2,844,985	6.76	101,145,337	3.74	3.82
	2030	98,092,150	32,697,383	130,789,533	7.19	1,720,148,549	2.95	3.25
	2040	363,049,116	121,016,372	484,065,488	7.41	3,626,241,629	2.59	3.15
	2050	449,206,966	149,735,655	598,942,621	7.76	4,486,811,644	2.41	3.04
EAST NORTH CENTRAL								
	2010	0	0	0	0.00	133,391	3.59	3.59
	2020	7,101,434	0	7,101,434	4.95	140,205,491	3.61	3.67
	2030	270,171,277	90,057,092	360,228,370	5.69	2,261,707,901	3.07	3.43
	2040	999,931,634	333,310,545	1,333,242,179	5.95	4,489,191,008	2.64	3.40
	2050	1,237,232,749	412,410,916	1,649,643,665	6.45	5,554,553,873	2.46	3.37
WEST NORTH CENTRAL								
	2010	0	0	0	0.00	64,949	4.69	4.69
	2020	6,204,418	0	6,204,418	6.32	65,520,577	3.77	3.99
	2030	247,355,678	82,451,893	329,807,571	6.75	946,835,505	3.64	4.44
	2040	915,488,760	305,162,920	1,220,651,680	7.10	1,614,340,574	3.58	5.09
	2050	1,132,750,117	377,583,372	1,510,333,489	7.45	1,997,451,583	2.83	4.82

TABLE 4.9 (Cont.)

		Non-Metro Areas				Metro Areas		
Region	**Year**	**Distributed Production Total GEG**	**Centralized Production Total GEG**	**Total GEG**	**Weighted Cost ($/GGE)**	**Centralized Production Total GEG**	**Weighted Cost ($/GGE)**	**Total Weighted Cost ($/GGE)**
SOUTH ATLANTIC								
	2010	0	0	0	0.00	167,341	3.56	3.56
	2020	10,082,569	0	10,082,569	6.62	174,716,175	3.58	3.75
	2030	349,349,043	116,449,681	465,798,724	6.96	2,823,459,608	2.97	3.53
	2040	1,292,976,673	430,992,224	1,723,968,897	7.13	5,580,360,764	2.50	3.59
	2050	1,599,822,456	533,274,152	2,133,096,608	7.13	6,904,677,132	2.47	3.57
EAST SOUTH CENTRAL								
	2010	0	0	0	0.00	57,432	4.48	4.48
	2020	4,927,336	0	4,927,336	5.90	58,496,403	3.59	3.77
	2030	222,441,131	74,147,044	296,588,174	6.31	832,299,705	3.13	3.97
	2040	823,277,461	274,425,820	1,097,703,281	6.50	1,409,174,681	2.97	4.51
	2050	1,018,655,477	339,551,826	1,358,207,303	6.84	1,743,596,267	2.54	4.42
WEST SOUTH CENTRAL								
	2010	0	0	0	0.00	102,355	4.51	4.51
	2020	7,075,599	0	7,075,599	5.49	105,956,951	3.62	3.73
	2030	234,242,938	78,080,979	312,323,917	6.66	1,699,558,035	3.25	3.78
	2040	866,957,161	288,985,720	1,155,942,881	7.32	3,311,766,108	2.79	3.96
	2050	1,072,701,128	357,567,043	1,430,268,170	8.15	4,097,705,628	2.60	4.04
MOUNTAIN								
	2010	0	0	0	0.00	55,686	4.81	4.81
	2020	6,363,295	0	6,363,295	6.50	55,132,280	3.07	3.43
	2030	174,310,843	58,103,614	232,414,458	6.58	862,153,755	3.82	4.40
	2040	645,142,327	215,047,442	860,189,769	7.01	1,570,475,827	4.08	5.12
	2050	798,245,787	266,081,929	1,064,327,716	7.25	1,943,176,971	3.00	4.51

TABLE 4.9 (Cont.)

Region	Year	Non-Metro Areas: Distributed Production Total GEG	Non-Metro Areas: Centralized Production Total GEG	Non-Metro Areas: Total GEG	Non-Metro Areas: Weighted Cost ($/GGE)	Metro Areas: Centralized Production Total GEG	Metro Areas: Weighted Cost ($/GGE)	Total Weighted Cost ($/GGE)
CONTIGUOUS PACIFIC								
	2010	0	0	0	0.00	120,283	3.77	3.77
	2020	2,591,631	0	2,591,631	6.72	130,239,368	3.78	3.83
	2030	79,666,107	26,555,369	106,221,476	7.33	2,258,055,785	3.23	3.42
	2040	294,852,440	98,284,147	393,136,586	7.82	4,857,123,132	2.70	3.08
	2050	364,826,036	121,608,679	486,434,715	8.55	6,009,802,670	2.52	2.97
ALASKA								
	2010	0	0	0	0.00	1,614	4.79	4.79
	2020	324,419	0	324,419	7.86	1,458,036	3.83	4.56
	2030	8,814,973	2,938,324	11,753,297	7.38	19,972,849	3.44	4.90
	2040	32,625,120	10,875,040	43,500,160	7.97	26,952,874	3.30	6.18
	2050	40,367,627	13,455,876	53,823,503	8.74	33,349,258	3.27	6.65
HAWAII								
	2010	0	0	0	0.00	2,501	5.60	5.60
	2020	0	0	0	0.00	2,762,137	4.18	4.18
	2030	7,005,576	2,335,192	9,340,768	9.38	39,822,896	3.18	4.36
	2040	25,928,356	8,642,785	34,571 ,142	8.63	74,604,719	3.10	4.85
	2050	32,081,605	10,693,868	42,775,473	8.58	92,309,712	2.62	4.51
UNITED STATES								
	2010	0	0	0	0.00	840,335	4.03	4.03
	2020	48,544,958	0	48,544,958	6.16	879,455,042	3.63	3.76
	2030	1,739,595,945	579,865,315	2,319,461,260	6.68	14,198,138,740	3.18	3.67
	2040	6,438,423,182	2,146,141,061	8,584,564,243	7.01	28,095,435,757	2.79	3.77
	2050	7,966,372,640	2,655,457,547	10,621,830,186	7.37	34,762,969,814	2.55	3.68

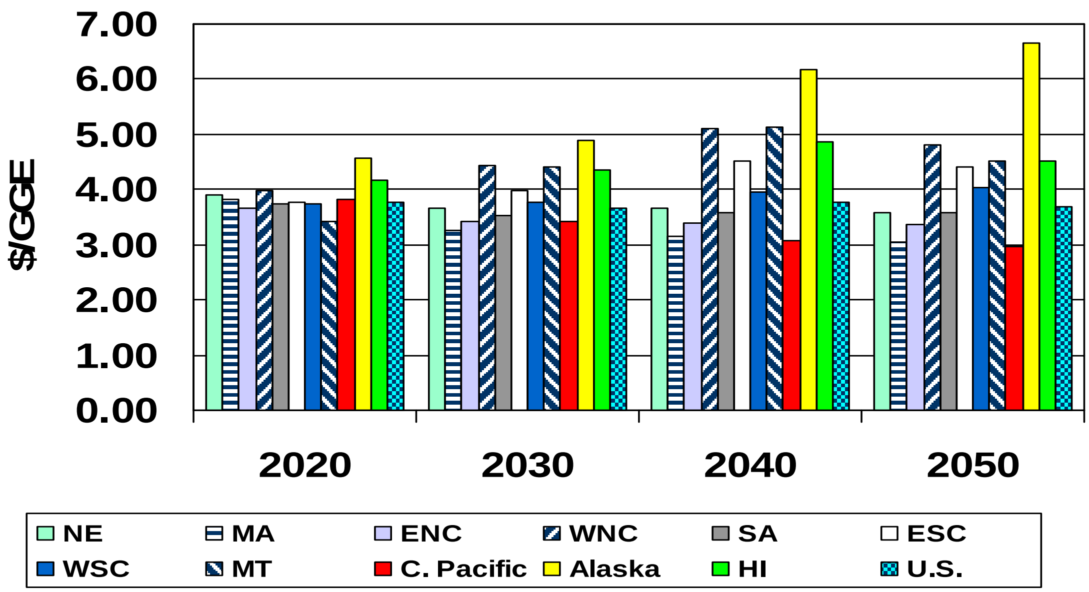

Figure 4.3 Regional H_2 Costs in GYOW

Table 4.10 Sensitivity Cases Altering Distributed Production Assumptions of GYOW: U.S. Average H_2 Cost

	H_2 Cost ($/GGE), by Year				
Scenario	**2010**	**2020**	**2030**	**2040**	**2050**
GYOW	4.03	3.76	3.67	3.77	3.68
GYOW with Continued Use of Natural Gas for Distributed Production to 2050 (65% of all distributed production in 2050)	4.03	3.76	3.52	3.31	3.10
GYOW with Cost of Distributed Production from Electrolysis at 50% of Original GYOW Cost	4.03	3.67	3.35	3.09	2.89
GYOW with 100% of FCV Travel in Non-Metropolitan Areas Served by Distributed Production	4.03	3.76	3.83	4.17	4.10

Table 4.11 Sensitivity Cases Altering Distributed Production Assumptions of GYOW: Average U.S. Metropolitan (M) and Non-Metropolitan (NM) H_2 Cost

	H_2 Cost ($/GGE), by Year									
	2010		2020		2030		2040		2050	
Scenario	**M**	**NM**	**M**	**NM**	**M**	**NM**	**M**	**NM**	**M**	**NM**
GYOW	4.03	-	3.63	6.16	3.18	6.68	2.79	7.01	2.55	7.37
GYOW with Continued Use of Natural Gas for Distributed Production to 2050	4.03	-	3.63	6.16	3.18	5.60	2.79	5.04	2.55	4.90
GYOW with Cost of Distributed Production from Electrolysis at 50% of Original GYOW Cost	4.03	-	3.63	4.43	3.18	4.41	2.79	4.07	2.55	4.01
GYOW with 100% of FCV Travel in Non-Metropolitan Areas Served by Distributed Production	4.03	-	3.63	6.16	3.18	7.83	2.88	8.37	2.61	8.96

5 ALTERNATIVE SCENARIOS IN REGIONAL H_2 MODEL

As indicated previously, the Regional H_2 Model used to develop regional H_2 production and cost estimates for the GYOW scenario can be used to develop such estimates for alternative scenarios. The current version of the model is called "Regional H_2 Model 1.0." It is an Excel spreadsheet model. In its current form, it is not "user-friendly," but it is somewhat flexible. The alternative scenarios that can be evaluated most easily include those that assume:

1. Alternative national total H_2 demand,

2. Alternative percentages of non-metropolitan travel served by distributed H_2 production, and

3. Alternative estimates of the share of distributed H_2 production that will be provided by steam reforming of natural gas versus electrolysis.

In Section 4.5, we saw the results of altering assumptions 2 and 3.

Alternative evaluations of regional resource fuels, alternative assumptions guiding the use of these fuels over time and at various demand levels, and alternative regional H_2 fuel costs by type of resource fuel can also be input to the model, although not as easily as the three factors listed above. Considerable work remains to enhance the flexibility of this model to evaluate a wide variety of alternative scenarios (e.g., including those that allow FCVs to penetrate the regions assuming different start dates).

Appendix C contains a summary of the key assumptions underlying the existing version of the model.

6 ISSUES REQUIRING FURTHER ANALYSIS

Obviously, there are many issues involved in adequately estimating what resources might be used to produce H_2 and what H_2 costs will be regionally and nationally. The list below reflects some of the issues that we faced and others that we believe need to addressed in order to develop reliable estimates of regional H_2 demand, production, and cost. The list is not meant to be exhaustive.

6.1 ISSUES RELATED TO ESTIMATES OF H_2 PRODUCTION FROM VARIOUS RESOURCE FUELS

6.1.1 Resource Potential of H_2 Resource Fuels

Are the assessments of the resource potential of each resource fuel accurate or can better data be used? The data used to assess coal and natural gas resources in this report are very good. The methodology used to weight natural gas reserves and the existing natural gas distribution system into an overall resource potential for H_2 production from natural gas should be reviewed for potential revision. The biomass volumes per state were taken from a well-developed reference; however, they may require updating. The wind and solar resource assessments can be updated with more in-depth analysis and better data: we used maps illustrating their potential, not the data supporting the maps. The potential for existing power plants to provide electricity for H_2 production and the potential for H_2 generation via thermochemical water splitting by using advanced, high-temperature nuclear reactors is simply based on assumption and requires further evaluation.

6.1.2 Development of Regional H_2 Supply Curves

Can we bring delivered H_2 cost estimates for the various resource fuel pathways to bear on evaluating the relative attractiveness of each H_2 pathway in each region? Use of regional H_2 supply curves (volume of H_2 available at specific costs — from different pathways) would be a preferable way to evaluate the degree to which alternative resource fuels are used to produce H_2. DTI used such curves when evaluating the potential for renewable resources to supply H_2 (Myers et al. 2003). DTI's analysis was conducted at the state level and considered competing demand for the renewable resources. But it did not consider fossil or nuclear resource fuels.

6.1.3 Interregional Production and Transport of H_2

We assume that each Census region's demand is met by production from resource fuels in that Census region only. We expect that the market will evolve differently and that, for many regions, some regional H_2 demand will be met by H_2 produced externally to those regions. This latter assumption needs to be evaluated. For example, coal is currently shipped from one Census region to another for use in power plants. (A review of National Mining Association data indicates that over 20 states consume much more coal per year [10 million tons] than they produce (NMA 2004a,b). It could be so shipped for H_2 production, and a region's H_2 demand would thus be met partially by resources from outside the region. DTI's methodology appears to have resulted in H_2 demand in one region being met by H_2 produced from another region (Myers et al. 2003).

6.2 ISSUES RELATED TO H_2 DEMAND, ESPECIALLY IN NON-METROPOLITAN AREAS, AND THE REFUELING FACILITIES THAT NEED TO BE ESTABLISHED TO SERVE THAT DEMAND

6.2.1 Rural Travel Requirements

In general, ensuring that H_2 is available for FCV travel in rural or non-metropolitan areas is a major concern. To analyze and address that concern, we need to know what the level of H_2 demand in non-metropolitan areas will be. One issue to be considered is whether we should expect FCVs to eventually fulfill the same rural travel requirements as the average vehicle today. In our analysis, we assumed that FCVs gradually will be used to meet the same rural travel requirements as the average vehicle today. We believe that assumption should be examined for any market penetration level that is less than 100%.

6.2.2 Nature of Rural Interstate Travel

What is the nature of rural interstate travel? An assumption of our analysis is that the first travel by FCVs in non-metropolitan areas will be on interstates between metropolitan areas. But to determine how much H_2 will be required by FCVs for that travel, we need to better understand the purpose of rural interstate travel in general. For example, how much rural interstate travel is (1) business-related by urban residents, (2) by residents of rural areas traveling from one rural location to another, and (3) "other" (such as vacation and visiting friends, etc.)?

6.2.3 Potential Changes in Rural or Non-Metropolitan Travel

Will the magnitude of the average light vehicle's rural or non-metropolitan travel change in the future? In this analysis, we have relied on existing travel data for non-metropolitan areas to estimate potential H_2 demand by FCVs in those areas. Will the United States become more urban and metropolitan? We are concerned that we may be relying too much on existing relationships rather than projections to estimate the amount of rural travel the average FCV will make.

6.2.4 Magnitude of FCV Refueling Infrastructure in Non-Metropolitan Areas

Should we expect the FCV refueling infrastructure in non-metropolitan areas to be the same as that which we have now? Will there need to be the same number of stations in essentially the same locations? Our analysis makes this assumption for non-metropolitan areas, but other options are possible.

6.2.5 Number of Gasoline-Refueling Facilities

How many total gasoline-refueling facilities exist, by metropolitan versus non-metropolitan designation? How does the fact that there has been a downward trend in the total number of stations affect the analysis? The U.S. Census provides one set of total estimates of the number of gasoline stations in the United States (by county, which can be classified as metropolitan or non-metropolitan), while the National Petroleum News (NPN) survey (Davis and Diegel 2002) has a much higher total (approximately 120,000 versus 175,000) (U.S. Census Bureau 2000). The U.S. Census only includes stations for which the refueling facility at the station is the "primary business activity." This type of station may be the only type to be considered for conversion to dispensing H_2, but if rural inhabitants get a good part of their gasoline from refueling facilities that are small and not the "primary business activity" of the establishment, then providing H_2 to that population may be more difficult. Ideally, we would obtain data that provide the number of stations by (1) whether or not being a refueling facility is the primary business activity, (2) volume dispensed, and (3) county.

Both the U.S. Census and NPN indicate a trend toward fewer total service stations over time. We need to analyze the implications for use of H_2 in rural areas. It would be interesting to know if there is any difference in the trend for metropolitan versus non-metropolitan stations.

6.2.6 Status of Non-Metropolitan Interstate Refueling Locations

How many non-metropolitan interstate refueling locations exist today and what is the average distance between these facilities? We estimated an average distance of 30 miles between fueling stations along largely rural interstates. We did so by looking at maps of toll roads in several states (e.g., PA, OH, IN, IL, and KS) (Pennsylvania Turnpike 2003, Kansas Turnpike Authority 2003, and Ohio Turnpike 2003). We think we should get better and/or additional data and might be able to do so from the web (perhaps with Map Quest) or Microsoft MapPoint. (We note that Melaina uses 50- and 20-mile intervals in his scenarios, but we are unsure how he selected those distances [Melaina 2003]. California is planning on 20-mile intervals [EV World 2004].)

6.2.7 Travel Distances to Refuel

How far do drivers now travel in non-metropolitan versus metropolitan areas to refuel with a gasoline or diesel car/light truck (or current alternative fuels)? How much farther might they be willing to travel to refuel with an FCV? If we knew the current distances drivers travel to refueling stations and what additional distance drivers say they would be willing to travel for their fuel, we would be better able to estimate what a "reasonable" additional distance might be for an FCV. The results of one survey indicate that drivers in non-metropolitan areas travel 1.4 miles (or 70%) farther to refuel than do drivers in metropolitan areas (ORC 2004). We need to verify these results. Also, to evaluate how much farther they would be willing to drive for fuel, we might ask in a survey about how much farther they would be willing to drive for considerably less-expensive fuel. Although H_2 would not be less expensive, we would get some indication of acceptable extra travel distances.

6.2.8 Distributed Production in Non-Metropolitan Areas in Low-H_2-Demand Scenarios

What transitional assumptions should be modified when making estimates for scenarios with lower FCV penetration? Our analysis focuses on estimating the amount of distributed production in non-metropolitan areas required for a substantial level of FCV penetration (nearly 50% of light-vehicle stock by 2050). We think the transitional assumptions that we made in GYOW should be modified when making estimates for scenarios with much lower maximum FCV penetration (i.e., 10%). However, we are not sure what they should be.

6.2.9 Alternative Assumptions for Provision of H_2 to Non-Metropolitan Areas

Distributed production via electrolysis is expensive, but given the assumption by the DOE Office of Hydrogen, Fuel Cells and Infrastructure Technologies (OHFCIT) that no natural gas will be used to produce H_2 by 2050 and our assumption that distributed production will either use natural gas or electrolysis, electrolysis will be used to produce 100% of distributed H_2 by 2050. What are the impacts of making alternative assumptions? Other options exist, such as additional use of highway distribution from centralized production plants and/or the extension of H_2 pipelines that the scenario postulates will exist. In particular, the use of rights-of-way and/or existing abandoned natural gas or petroleum pipelines to move H_2 may facilitate some distribution of H_2 into non-metropolitan areas. An analysis of how to minimize distribution costs to these locations should be considered. Also, it might be useful to estimate what national average price of natural gas would cause a distributed gas-based system to be equal in cost to a distributed electricity-based system. This cost could then be compared with estimates of the future cost of imported natural gas. Higher levels of natural gas imports to provide the H_2 for fuel cell vehicles is another option.

6.2.10 Reasonable Upper Bound on Distributed Production

What is a reasonable upper bound on distributed production? The DTI analysis of the potential for renewables to provide 10 quads of H_2 appears to indicate that over 70% of H_2 would be "distributed" (i.e., generated at service stations), because of the cost of production from various renewable pathways (Myers et al. 2003). We estimated approximately 20% on the basis of the amount of non-metropolitan travel.

6.3 ISSUES RELATED IN PARTICULAR TO THE EARLY YEARS OF FCV MARKET PENETRATION

6.3.1 Phase-In of FCVs by U.S. Census Division

This analysis does not include any phase-in of FCVs by the U.S. Census Division. Will FCVs likely be introduced in specific regions initially, or should we continue to assume universal market penetration? This analysis is largely a regional analysis, with some consideration of the transition to FCV use. We think it is likely that FCVs will penetrate the vehicle market at different rates in different regions. We suggest the following as an initial sequence among the Census regions:

1. West (contiguous Pacific) and Hawaii;
2. New England and Middle Atlantic;
3. East North Central;
4. South Atlantic;
5. West South Central;
6. East South Central; and
7. Mountain, West North Central, and Alaska.

This order is based on "brainstorming" done by the EERE/PBA Transportation Analytic Team (Singh et al. 2004).

6.3.2 Distributed H_2 Production in Metropolitan Areas

Where will H_2 provided in metropolitan areas be produced? We assumed that all H_2 provided in metropolitan areas would be centrally produced. We think that in the very early years of a transition to H_2, some H_2 will be generated at stations in metropolitan areas. Two questions are "how much?" and "how quickly can centrally produced H_2 be provided to all urban areas?" An alternative question is if sizeable distributed production facilities are established in the early years in metropolitan areas, will those facilities inhibit or preclude delivery of H_2 from centralized production facilities?

6.4 ISSUES RELATED TO H_2 PATHWAY COST ESTIMATES

Potential refinements to the H_2 cost analysis can be made. In general, once the H2A group has completed development of its analysis tool, we will review it and consider it where possible in future work (Mann 2004). Other potential refinements include the following:

Additional analysis of opportunities to reduce the costs of production equipment: These results could be reasonably expected to occur as a result of technology breakthroughs, both due to DOE-funded programs and other efforts.

Additional investigation of the cost of electricity from renewable resources: EIA does not provide cost projections for electricity from renewable resources. One reference indicates that the price of electricity from renewables needs to drop to the price of current commercial sector electricity to be viable.

Comparison of investment cost of near-term transportation options — high pressure vs. liquefied tanker — including compression and refrigeration costs at the process plants: Our estimates for the cost of moving H_2 from centralized production facilities assume that in the early years, it is moved by refrigerated truck and later by pipeline. To move it by refrigerated truck requires the construction of a liquefaction unit at the H_2 production facility that is not needed when the H_2 begins to be moved by pipeline. We need to explore whether tube trailers might be the more cost-effective, near-term initial transport option from a total investment perspective.

Analysis of other options for distributing hydrogen in non-metropolitan locations: In particular, we might develop a scenario for extended pipeline transmission of H_2 (neat or as a blend) through the existing natural gas distribution system *after* natural gas resource availability and pipeline shipment diminishes. This issue was also addressed under Section 6.2.8. An analysis that is more detailed than the macroscopic, regional approach applied in the work to date is needed to address this issue. The analysis could include the use of GIS technology to identify pipeline locations relative to markets and population centers.

Additional analysis of the potential right-of-way costs for H_2 pipelines, as well as pipeline costs associated with reutilization of existing rights-of-way: In Section 4.2.3, we explained why we did not include pipeline right-of-way costs in our analysis: we believe they would average less than 5% of total construction costs. However, we recognize that the magnitude of the H_2 infrastructure that would need to be developed to support a sizeable FCV market penetration suggests that further analysis of total right-of-way costs is warranted. We are particularly concerned about the costs of pipelines in dense urban areas. We think that analysis should also address the higher construction costs likely to occur with reutilization of existing pipeline rights-of-way.

Reexamination of the most likely H_2 delivery pathways: We assumed that, by 2030, most H_2 produced centrally would be delivered to stations by pipeline. We think that a mix of delivery modes should be considered and the effect on delivery costs estimated (i.e., pipeline from the central production plant to a terminal and then truck).

Development of an estimate of the total investment required to fund the infrastructure development — both production and distribution: The DOE/NRC "2050" study developed such an estimate for a version of the GYOW scenario that assumed use of H_2 in metropolitan areas only (see the 2050 Phase II study at http://www.ott.doe.gov/future_highway.shtml) (Patterson et al. 2003). We should develop an estimate for the scenario we have analyzed here and compare it to that study.

Assessment and update of the production capacity requirements for plants by region and by resource fuel and implications for delivery costs: We have estimated centralized production costs by assuming that the size of production facility will be the same for all resource fuels. Instead, the H2A team indicates that optimum sizes will vary by resource fuel (Mann 2004). It is possible that they will also vary by region. We need to examine, in particular, the costs of the optimum-sized plants for each resource fuel and see if they also vary by region. We should include city-gate production facilities (the size of which is "between" that of centralized and distributed production facilities) in these estimates. We also need to examine the effect of these different plant sizes on delivery costs (i.e., fewer large plants may mean longer delivery distances).

Additional analysis of the wind, solar, and nuclear-thermal technology processes and costs: Although all of the analyses and estimates include many assumptions based on professional judgments, the characterization of these costs was more limited than that for other resources. The DTI report may be of some help until the H2A analysis is complete (Myers 2003, Mann 2004).

Analysis of the potential for distributed production of H_2 via ethanol reforming: Hydrogen may be produced at stations by reforming ethanol. We did not include this method of distributed production in our analysis and need to examine if it may lead to lower costs in some regions.

Calculation of costs using DOE H_2 program goals: Our cost estimates are generally higher than DOE's H_2 program goals. We need to input the program cost goals into our model to examine the implications of these national average goals on our regional results.

6.5 OTHER ISSUES

Other issues that need to be addressed include:

- *Effects of a regionally diverse expansion of extraction and harnessing of natural resources to produce H_2 on air and water pollutants and land use:* The U.S. EPA has begun to examine the implications of the H_2 economy on air emissions and quality at the national and regional levels (Yeh and Loughlin 2005).

- *Availability of grid-connected FCVs:* If grid-connected hybrid FCVs were available, their drivers would have different concerns about the availability of refueling facilities than those with "pure" FCVs. Should we consider these vehicle types in future analyses? Is anyone thinking of these vehicle types?

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APPENDIX A: COST ESTIMATES BY RESOURCE FUEL INPUT TO REGIONAL H_2 MODEL

Table A.1 Centralized Production, Delivery, and Dispensing of H_2 Using Natural Gas

Hydrogen Production, Dispensing, and Delivery Cost Estimates, SMR-New England

Year	Hydrogen Production Cost, ($/GEG)	Carbon Sequestration	Delivery Cost ($/GEG)	Dispensing Cost	Total Hydrogen Cost ($/GEG)	Comments
2010	2.35	0.00	0.05	1.13	3.52	Delivered via Cryo-Tanker
2020	1.48	0.00	0.05	0.99	2.51	Delivered via Cryo-Tanker
2030	2.62	0.00	0.05	0.86	3.52	Delivered via Cryo-Tanker
2040	2.21	0.00	0.05	0.72	2.98	Delivered via Cryo-Tanker
2050	2.93	0.00	0.05	0.52	3.50	Delivered via Cryo-Tanker

Hydrogen Production, Dispensing, and Delivery Cost Estimates, SMR-Middle Atlantic Region

Year	Hydrogen Production Cost, ($/GEG)	Carbon Sequestration	Delivery Cost ($/GEG)	Dispensing Cost	Total Hydrogen Cost ($/GEG)	Comments
2010	2.29	0.00	0.03	1.13	3.45	Delivered via Cryo-Tanker
2020	2.43	0.00	0.03	0.99	3.46	Delivered via Cryo-Tanker
2030	2.52	0.00	0.03	0.86	3.41	Delivered via Cryo-Tanker
2040	2.61	0.00	0.03	0.72	3.37	Delivered via Cryo-Tanker
2050	2.71	0.00	0.03	0.52	3.27	Delivered via Cryo-Tanker

Hydrogen Production, Dispensing, and Delivery Cost Estimates, SMR-East North Central Region

Year	Hydrogen Production Cost, ($/GEG)	Carbon Sequestration	Delivery Cost ($/GEG)	Dispensing Cost	Total Hydrogen Cost ($/GEG)	Comments
2010	2.09	0.00	0.07	1.13	3.29	Delivered via Cryo-Tanker
2020	2.20	0.00	0.07	0.99	3.26	Delivered via Cryo-Tanker
2030	2.29	0.00	0.07	0.86	3.21	Delivered via Cryo-Tanker
2040	2.38	0.00	0.07	0.72	3.17	Delivered via Cryo-Tanker
2050	2.49	0.00	0.07	0.52	3.08	Delivered via Cryo-Tanker

Table A.1 (Cont.)

Hydrogen Production, Dispensing, and Delivery Cost Estimates, SMR-West North Central Region

Year	Hydrogen Production Cost, ($/GEG)	Carbon Sequestration	Delivery Cost ($/GEG)	Dispensing Cost	Total Hydrogen Cost ($/GEG)	Comments
2010	2.13	0.00	0.29	1.13	3.54	Delivered via Cryo-Tanker
2020	2.19	0.00	0.29	0.99	3.47	Delivered via Cryo-Tanker
2030	2.32	0.00	0.29	0.86	3.47	Delivered via Cryo-Tanker
2040	2.47	0.00	0.29	0.72	3.49	Delivered via Cryo-Tanker
2050	2.65	0.00	0.29	0.52	3.46	Delivered via Cryo-Tanker

Hydrogen Production, Dispensing, and Delivery Cost Estimates, SMR-South Atlantic

Year	Hydrogen Production Cost, ($/GEG)	Carbon Sequestration	Delivery Cost ($/GEG)	Dispensing Cost	Total Hydrogen Cost ($/GEG)	Comments
2010	2.06	0.00	0.07	1.13	3.25	Delivered via Cryo-Tanker
2020	2.15	0.00	0.07	0.99	3.21	Delivered via Cryo-Tanker
2030	2.20	0.00	0.07	0.86	3.12	Delivered via Cryo-Tanker
2040	2.25	0.00	0.07	0.72	3.04	Delivered via Cryo-Tanker
2050	2.31	0.00	0.07	0.52	2.89	Delivered via Cryo-Tanker

Hydrogen Production, Dispensing, and Delivery Cost Estimates, SMR-East South Central Region

Year	Hydrogen Production Cost, ($/GEG)	Carbon Sequestration	Delivery Cost ($/GEG)	Dispensing Cost	Total Hydrogen Cost ($/GEG)	Comments
2010	2.02	0.00	0.10	1.13	3.25	Delivered via Cryo-Tanker
2020	2.12	0.00	0.10	0.99	3.21	Delivered via Cryo-Tanker
2030	2.16	0.00	0.10	0.86	3.12	Delivered via Cryo-Tanker
2040	2.21	0.00	0.10	0.72	3.04	Delivered via Cryo-Tanker
2050	2.26	0.00	0.10	0.52	2.88	Delivered via Cryo-Tanker

Table A.1 (Cont.)

Hydrogen Production, Dispensing, and Delivery Cost Estimates, SMR-West South Central Region

Year	Hydrogen Production Cost, ($/GEG)	Carbon Sequestration	Delivery Cost ($/GEG)	Dispensing Cost	Total Hydrogen Cost ($/GEG)	Comments
2010	2.03	0.00	0.14	1.13	3.30	Delivered via Cryo-Tanker
2020	2.13	0.00	0.14	0.99	3.26	Delivered via Cryo-Tanker
2030	2.22	0.00	0.14	0.86	3.21	Delivered via Cryo-Tanker
2040	2.31	0.00	0.14	0.72	3.17	Delivered via Cryo-Tanker
2050	2.41	0.00	0.14	0.52	3.07	Delivered via Cryo-Tanker

Hydrogen Production, Dispensing, and Delivery Cost Estimates, SMR-Mountain

Year	Hydrogen Production Cost, ($/GEG)	Carbon Sequestration	Delivery Cost ($/GEG)	Dispensing Cost	Total Hydrogen Cost ($/GEG)	Comments
2010	2.08	0.00	0.51	1.13	3.72	Delivered via Cryo-Tanker
2020	1.07	0.00	0.51	0.83	2.42	Delivered via Cryo-Tanker
2030	1.23	0.00	0.51	0.72	2.47	Delivered via Cryo-Tanker
2040	1.43	0.00	0.51	0.61	2.55	Delivered via Cryo-Tanker
2050	1.67	0.00	0.51	0.44	2.61	Delivered via Cryo-Tanker

Hydrogen Production, Dispensing, and Delivery Cost Estimates, SMR-Pacific

Year	Hydrogen Production Cost, ($/GEG)	Carbon Sequestration	Delivery Cost ($/GEG)	Dispensing Cost	Total Hydrogen Cost ($/GEG)	Comments
2010	2.45	0.00	0.12	1.13	3.69	Delivered via Cryo-Tanker
2020	2.40	0.00	0.12	0.99	3.51	Delivered via Cryo-Tanker
2030	2.52	0.00	0.12	0.86	3.50	Delivered via Cryo-Tanker
2040	2.69	0.00	0.12	0.72	3.53	Delivered via Cryo-Tanker
2050	2.90	0.00	0.12	0.52	3.54	Delivered via Cryo-Tanker

Table A.2 Centralized Production, Delivery, and Dispensing of H_2 Using Coal with Carbon Sequestration

Hydrogen Production, Dispensing, and Delivery Cost Estimates, Coal Gasification-New England

Year	Hydrogen Production Cost, ($/GEG)	Carbon Sequestration	Delivery Cost ($/GEG)	Dispensing Cost	Total Hydrogen Cost ($/GEG)	Comments
2010	3.21	0.64	0.05	1.13	5.02	Cryogenic Tanker Delivery
2020	1.87	0.37	0.49	0.91	3.64	Mixed Cryo + Pipeline Delivery (50% each)
2030	1.64	0.33	0.23	0.72	2.92	Pipeline Delivery
2040	1.56	0.31	0.08	0.61	2.56	Pipeline Delivery
2050	1.49	0.30	0.07	0.44	2.30	Pipeline Delivery

Hydrogen Production, Dispensing, and Delivery Cost Estimates, Coal Gasification-Middle Atlantic Region

Year	Hydrogen Production Cost, ($/GEG)	Carbon Sequestration	Delivery Cost ($/GEG)	Dispensing Cost	Total Hydrogen Cost ($/GEG)	Comments
2010	2.89	0.58	0.03	1.13	4.63	Cryogenic Tanker Delivery
2020	1.66	0.33	0.36	0.91	3.26	Mixed Cryo + Pipeline Delivery (50% each)
2030	1.46	0.29	0.17	0.72	2.64	Pipeline Delivery
2040	1.39	0.28	0.06	0.61	2.34	Pipeline Delivery
2050	1.33	0.27	0.05	0.44	2.09	Pipeline Delivery

Hydrogen Production, Dispensing, and Delivery Cost Estimates, Coal Gasification-East North Central Region

Year	Hydrogen Production Cost, ($/GEG)	Carbon Sequestration	Delivery Cost ($/GEG)	Dispensing Cost	Total Hydrogen Cost ($/GEG)	Comments
2010	2.79	0.56	0.07	1.13	4.54	Cryogenic Tanker Delivery
2020	1.62	0.32	0.66	0.91	3.51	Mixed Cryo + Pipeline Delivery (50% each)
2030	1.41	0.28	0.31	0.72	2.73	Pipeline Delivery
2040	1.34	0.27	0.11	0.61	2.32	Pipeline Delivery
2050	1.27	0.25	0.10	0.44	2.06	Pipeline Delivery

Table A.2 (Cont.)

Hydrogen Production, Dispensing, and Delivery Cost Estimates, Coal Gasification-West North Central Region

Year	Hydrogen Production Cost, ($/GEG)	Carbon Sequestration	Delivery Cost ($/GEG)	Dispensing Cost	Total Hydrogen Cost ($/GEG)	Comments
2010	2.75	0.55	0.29	1.13	4.72	Cryogenic Tanker Delivery
2020	1.57	0.31	2.75	0.91.	5.54	Mixed Cryo + Pipeline Delivery (50% each)
2030	1.37	0.27	1.31	0.72	3.67	Pipeline Delivery
2040	1.30	0.26	0.45	0.61	2.63	Pipeline Delivery
2050	1.25	0.25	0.40	0.44	2.33	Pipeline Delivery

Hydrogen Production, Dispensing, and Delivery Cost Estimates, Coal Gasification-South Atlantic

Year	Hydrogen Production Cost, ($/GEG)	Carbon Sequestration	Delivery Cost ($/GEG)	Dispensing Cost	Total Hydrogen Cost ($/GEG)	Comments
2010	2.86	0.57	0.07	1.13	4.63	Cryogenic Tanker Delivery
2020	1.66	0.33	0.56	0.91	3.47	Mixed Cryo + Pipeline Delivery (50% each)
2030	1.46	0.29	0.26	0.72	2.73	Pipeline Delivery
2040	1.38	0.28	0.09	0.61	2.36	Pipeline Delivery
2050	1.32	0.26	0.08	0.44	2.10	Pipeline Delivery

Hydrogen Production, Dispensing, and Delivery Cost Estimates, Coal Gasification-East South Central Region

Year	Hydrogen Production Cost, ($/GEG)	Carbon Sequestration	Delivery Cost ($/GEG)	Dispensing Cost	Total Hydrogen Cost ($/GEG)	Comments
2010	2.79	0.56	0.10	1.13	4.58	Cryogenic Tanker Delivery
2020	1.62	0.32	0.84	0.91	3.69	Mixed Cryo + Pipeline Delivery (50% each)
2030	1.41	0.28	0.40	0.72	2.81	Pipeline Delivery
2040	1.34	0.27	0.14	0.61	2.36	Pipeline Delivery
2050	1.28	0.26	0.12	0.44	2.10	Pipeline Delivery

Table A.2 (Cont.)

Hydrogen Production, Dispensing, and Delivery Cost Estimates, Coal Gasification-West South Central Region

Year	Hydrogen Production Cost, ($/GEG)	Carbon Sequestration	Delivery Cost ($/GEG)	Dispensing Cost	Total Hydrogen Cost ($/GEG)	Comments
2010	2.78	0.56	0.14	1.13	4.60	Cryogenic Tanker Delivery
2020	1.59	0.32	1.10	0.91	3.92	Mixed Cryo + Pipeline Delivery (50% each)
2030	1.41	0.28	0.52	0.72	2.93	Pipeline Delivery
2040	1.35	0.27	0.18	0.61	2.41	Pipeline Delivery
2050	1.31	0.26	0.16	0.44	2.17	Pipeline Delivery

Hydrogen Production, Dispensing, and Delivery Cost Estimates, Coal Gasification-Mountain

Year	Hydrogen Production Cost, ($/GEG)	Carbon Sequestration	Delivery Cost ($/GEG)	Dispensing Cost	Total Hydrogen Cost ($/GEG)	Comments
2010	2.79	0.56	0.51	1.13	4.99	Cryogenic Tanker Delivery
2020	1.60	0.32	4.59	0.91	7.42	Mixed Cryo + Pipeline Delivery (50% each)
2030	1.40	0.28	2.18	0.72	4.58	Pipeline Delivery
2040	1.33	0.27	0.75	0.61	2.96	Pipeline Delivery
2050	1.27	0.25	0.67	0.44	2.63	Pipeline Delivery

Hydrogen Production, Dispensing, and Delivery Cost Estimates, Coal Gasification-Pacific

Year	Hydrogen Production Cost, ($/GEG)	Carbon Sequestration	Delivery Cost ($/GEG)	Dispensing Cost	Total Hydrogen Cost ($/GEG)	Comments
2010	3.34	0.67	0.12	1.13	5.25	Cryogenic Tanker Delivery
2020	1.79	0.36	1.22	0.91	4.28	Mixed Cryo + Pipeline Delivery (50% each)
2030	1.55	0.31	0.59	0.72	3.16	Pipeline Delivery
2040	1.45	0.29	0.20	0.61	2.55	Pipeline Delivery
2050	1.36	0.27	0.18	0.44	2.25	Pipeline Delivery

Table A.3 Centralized Production, Delivery, and Dispensing of H_2 Using Biomass

Hydrogen Production, Dispensing, and Delivery Cost Estimates, Biomass Gasification-New England

Year	Hydrogen Production Cost, ($/GEG)	Carbon Sequestration	Delivery Cost ($/GEG)	Dispensing Cost	Total Hydrogen Cost ($/GEG)	Comments
2010	3.51	0.00	0.05	1.13	4.68	Cryogenic Tanker Delivery
2020	2.08	0.00	0.49	0.91	3.48	Mixed Cryo + Pipeline Delivery (50% each)
2030	1.83	0.00	0.23	0.72	2.78	Pipeline Delivery
2040	1.83	0.00	0.08	0.61	2.52	Pipeline Delivery
2050	1.84	0.00	0.07	0.44	2.35	Pipeline Delivery

Hydrogen Production, Dispensing, and Delivery Cost Estimates, Biomass Gasification-Middle Atlantic Region

Year	Hydrogen Production Cost, ($/GEG)	Carbon Sequestration	Delivery Cost ($/GEG)	Dispensing Cost	Total Hydrogen Cost ($/GEG)	Comments
2010	3.37	0.00	0.03	1.13	4.53	Cryogenic Tanker Delivery
2020	2.04	0.00	0.36	0.91	3.31	Mixed Cryo + Pipeline Delivery (50% each)
2030	1.78	0.00	0.17	0.72	2.67	Pipeline Delivery
2040	1.77	0.00	0.06	0.61	2.44	Pipeline Delivery
2050	1.77	0.00	0.05	0.44	2.26	Pipeline Delivery

Hydrogen Production, Dispensing, and Delivery Cost Estimates, Biomass Gasification-East North Central Region

Year	Hydrogen Production Cost, ($/GEG)	Carbon Sequestration	Delivery Cost ($/GEG)	Dispensing Cost	Total Hydrogen Cost ($/GEG)	Comments
2010	3.23	0.00	0.07	1.13	4.42	Cryogenic Tanker Delivery
2020	1.97	0.00	0.66	0.91	3.53	Mixed Cryo + Pipeline Delivery (50% each)
2030	1.71	0.00	0.31	0.72	2.74	Pipeline Delivery
2040	1.70	0.00	0.11	0.61	2.42	Pipeline Delivery
2050	1.69	0.00	0.10	0.44	2.23	Pipeline Delivery

Table A.3 (Cont.)

Hydrogen Production, Dispensing, and Delivery Cost Estimates, Biomass Gasification-West North Central Region

Year	Hydrogen Production Cost, ($/GEG)	Carbon Sequestration	Delivery Cost ($/GEG)	Dispensing Cost	Total Hydrogen Cost ($/GEG)	Comments
2010	3.21	0.00	0.29	1.13	4.62	Cryogenic Tanker Delivery
2020	1.94	0.00	2.75	0.91	5.60	Mixed Cryo + Pipeline Delivery (50% each)
2030	1.69	0.00	1.31	0.72	3.72	Pipeline Delivery
2040	1.69	0.00	0.45	0.61	2.75	Pipeline Delivery
2050	1.69	0.00	0.40	0.44	2.53	Pipeline Delivery

Hydrogen Production, Dispensing, and Delivery Cost Estimates, Biomass Gasification-South Atlantic

Year	Hydrogen Production Cost, ($/GEG)	Carbon Sequestration	Delivery Cost ($/GEG)	Dispensing Cost	Total Hydrogen Cost ($/GEG)	Comments
2010	3.22	0.00	0.07	1.13	4.41	Cryogenic Tanker Delivery
2020	1.94	0.00	0.56	0.91	3.41	Mixed Cryo + Pipeline Delivery (50% each)
2030	1.69	0.00	0.26	0.72	2.67	Pipeline Delivery
2040	1.69	0.00	0.09	0.61	2.38	Pipeline Delivery
2050	1.69	0.00	0.08	0.44	2.20	Pipeline Delivery

Hydrogen Production, Dispensing, and Delivery Cost Estimates, Biomass Gasification-East South Central Region

Year	Hydrogen Production Cost, ($/GEG)	Carbon Sequestration	Delivery Cost ($/GEG)	Dispensing Cost	Total Hydrogen Cost ($/GEG)	Comments
2010	3.20	0.00	0.10	1.13	4.43	Cryogenic Tanker Delivery
2020	1.93	0.00	0.84	0.91	3.68	Mixed Cryo + Pipeline Delivery (50% each)
2030	1.69	0.00	0.40	0.72	2.80	Pipeline Delivery
2040	1.68	0.00	0.14	0.61	2.43	Pipeline Delivery
2050	1.68	0.00	0.12	0.44	2.24	Pipeline Delivery

Table A.3 (Cont.)

Hydrogen Production, Dispensing, and Delivery Cost Estimates, Biomass Gasification-West South Central Region

Year	Hydrogen Production Cost, ($/GEG)	Carbon Sequestration	Delivery Cost ($/GEG)	Dispensing Cost	Total Hydrogen Cost ($/GEG)	Comments
2010	3.25	0.00	0.14	1.13	4.51	Cryogenic Tanker Delivery
2020	1.97	0.00	1.10	0.91	3.98	Mixed Cryo + Pipeline Delivery (50% each)
2030	1.73	0.00	0.52	0.72	2.98	Pipeline Delivery
2040	1.75	0.00	0.18	0.61	2.53	Pipeline Delivery
2050	1.77	0.00	0.16	0.44	2.36	Pipeline Delivery

Hydrogen Production, Dispensing, and Delivery Cost Estimates, Biomass Gasification-Mountain

Year	Hydrogen Production Cost, ($/GEG)	Carbon Sequestration	Delivery Cost ($/GEG)	Dispensing Cost	Total Hydrogen Cost ($/GEG)	Comments
2010	3.24	0.00	0.51	1.13	4.88	Cryogenic Tanker Delivery
2020	1.96	0.00	4.59	0.91	7.46	Mixed Cryo + Pipeline Delivery (50% each)
2030	1.71	0.00	2.18	0.72	4.62	Pipeline Delivery
2040	1.72	0.00	0.75	0.61	3.08	Pipeline Delivery
2050	1.72	0.00	0.67	0.44	2.83	Pipeline Delivery

Hydrogen Production, Dispensing, and Delivery Cost Estimates, Biomass Gasification-Pacific

Year	Hydrogen Production Cost, ($/GEG)	Carbon Sequestration	Delivery Cost ($/GEG)	Dispensing Cost	Total Hydrogen Cost ($/GEG)	Comments
2010	3.73	0.00	0.12	1.13	4.98	Cryogenic Tanker Delivery
2020	2.07	0.00	1.22	0.91	4.20	Mixed Cryo + Pipeline Delivery (50% each)
2030	1.79	0.00	0.59	0.72	3.09	Pipeline Delivery
2040	1.77	0.00	0.20	0.61	2.58	Pipeline Delivery
2050	1.75	0.00	0.18	0.44	2.37	Pipeline Delivery

Table A.4 Centralized Production of H_2 via Electrolysis

Hydrogen Production, Dispensing, and Delivery Cost Estimates, Electrolysis

Year	Hydrogen Production Cost, ($/GEG)	Dispensing and Delivery Cost ($/GEG)	Total Hydrogen Cost ($/GEG)	Comments
2010	4.63	2.72	7.36	Tube Trailer Delivery
2020	2.94	1.43	4.38	Tube trailer/pipeline mix
2030	2.78	0.97	3.75	Tube trailer/pipeline mix
2040	2.75	0.65	3.40	Tube trailer/pipeline mix
2050	2.62	0.49	3.11	Tube trailer/pipeline mix

Table A.5 Distributed Hydrogen Production and Dispensing Using Natural Gas

Distributed Hydrogen Production and Dispensing Cost Estimates, Natural Gas Resource-East South Central Region

Year	Station Size (# of Refills/Day)	Capital Recovery Cost ($/GEG)	Energy Costs ($/GEG)	Non-Energy Operating Costs ($/GEG)	Total Hydrogen Cost ($/GEG)
2010	79	2.26	1.25	0.75	4.27
2020	130	2.01	1.29	0.67	3.97
2030	55	2.44	1.29	0.81	4.55
2040	121	2.05	1.28	0.68	4.01
2050	150	1.96	1.27	0.65	3.88

Distributed Hydrogen Production and Dispensing Cost Estimates, Natural Gas Resource-West South Central Region

Year	Station Size (# of Refills/Day)	Capital Recovery Cost ($/GEG)	Energy Costs ($/GEG)	Non-Energy Operating Costs ($/GEG)	Total Hydrogen Cost ($/GEG)
2010	79	2.26	1.09	0.75	4.11
2020	102	2.15	1.14	0.72	4.00
2030	55	2.44	1.16	0.81	4.41
2040	122	2.05	1.17	0.68	3.90
2050	151	1.96	1.18	0.65	3.79

Distributed Hydrogen Production and Dispensing Cost Estimates, Natural Gas Resource-West North Central Region

Year	Station Size (# of Refills/Day)	Capital Recovery Cost ($/GEG)	Energy Costs ($/GEG)	Non-Energy Operating Costs ($/GEG)	Total Hydrogen Cost ($/GEG)
2010	79	2.26	1.11	0.75	4.13
2020	72	2.32	1.15	0.77	4.24
2030	52	2.48	1.25	0.83	4.56
2040	115	2.08	1.35	0.69	4.12
2050	142	1.99	1.46	0.66	4.11

Table A.5 (Cont.)

Distributed Hydrogen Production and Dispensing Cost Estimates, Natural Gas Resource-New England Region

Year	Station Size (# of Refills/Day)	Capital Recovery Cost ($/GEG)	Energy Costs ($/GEG)	Non-Energy Operating Costs ($/GEG)	Total Hydrogen Cost ($/GEG)
2010	79	2.26	1.40	0.75	4.42
2020	89	2.19	1.44	0.73	4.37
2030	61	2.42	1.52	0.81	4.74
2040	136	1.99	1.57	0.66	4.23
2050	169	1.90	1.64	0.63	4.17

Distributed Hydrogen Production and Dispensing Cost Estimates, Natural Gas Resource-South Atlantic Region

Year	Station Size (# of Refills/Day)	Capital Recovery Cost ($/GEG)	Energy Costs ($/GEG)	Non-Energy Operating Costs ($/GEG)	Total Hydrogen Cost ($/GEG)
2010	79	2.26	1.32	0.75	4.34
2020	160	1.93	1.35	0.64	3.92
2030	58	2.41	1.35	0.80	4.56
2040	128	2.02	1.33	0.67	4.03
2050	159	1.93	1.32	0.64	3.89

Distributed Hydrogen Production and Dispensing Cost Estimates, Natural Gas Resource-Pacific Region (except Alaska)

Year	Station Size (# of Refills/Day)	Capital Recovery Cost ($/GEG)	Energy Costs ($/GEG)	Non-Energy Operating Costs ($/GEG)	Total Hydrogen Cost ($/GEG)
2010	79	2.26	1.32	0.75	4.33
2020	105	2.13	1.30	0.71	4.13
2030	68	2.36	1.42	0.78	4.56
2040	151	1.96	1.54	0.65	4.15
2050	186	1.87	1.68	0.62	4.16

Table A.5 (Cont.)

Distributed Hydrogen Production and Dispensing Cost Estimates, Natural Gas Resource-Mountain Region

Year	Station Size (# of Refills/Day)	Capital Recovery Cost ($/GEG)	Energy Costs ($/GEG)	Non-Energy Operating Costs ($/GEG)	Total Hydrogen Cost ($/GEG)
2010	79	2.26	1.08	0.75	4.09
2020	52	2.48	1.12	0.83	4.42
2030	76	2.29	1.26	0.76	4.31
2040	168	1.90	1.39	0.63	3.93
2050	208	1.81	1.55	0.60	3.96

Distributed Hydrogen Production and Dispensing Cost Estimates, Natural Gas Resource-Middle Atlantic Region

Year	Station Size (# of Refills/Day)	Capital Recovery Cost ($/GEG)	Energy Costs ($/GEG)	Non-Energy Operating Costs ($/GEG)	Total Hydrogen Cost ($/GEG)
2010	79	2.26	1.24	0.75	4.26
2020	115	2.08	1.30	0.69	4.07
2030	65	2.38	1.34	0.79	4.52
2040	145	1.98	1.37	0.66	4.01
2050	179	1.87	1.41	0.62	3.90

Distributed Hydrogen Production and Dispensing Cost Estimates, Natural Gas Resource-East North Central Region

Year	Station Size (# of Refills/Day)	Capital Recovery Cost ($/GEG)	Energy Costs ($/GEG)	Non-Energy Operating Costs ($/GEG)	Total Hydrogen Cost ($/GEG)
2010	79	2.26	1.13	0.75	4.15
2020	114	2.08	1.18	0.69	3.96
2030	65	2.39	1.24	0.79	4.42
2040	143	1.98	1.29	0.66	3.93
2050	177	1.87	1.34	0.62	3.84

Table A.5 (Cont.)

Distributed Hydrogen Production and Dispensing Cost Estimates, Natural Gas Resource-Alaska

Year	Station Size (# of Refills/Day)	Capital Recovery Cost ($/GEG)	Energy Costs ($/GEG)	Non-Energy Operating Costs ($/GEG)	Total Hydrogen Cost ($/GEG)
2010	79	2.26	1.32	0.75	4.33
2020	12	3.44	1.30	1.15	5.89
2030	70	2.34	1.42	0.78	4.54
2040	155	1.94	1.54	0.65	4.13
2050	192	1.85	1.68	0.62	4.15

Table A.6 Distributed Hydrogen Production and Dispensing Using Electrolysis — Detailed Results for Selected Regions

Distributed Hydrogen Production and Dispensing Cost Estimates, Commercial Electricity South Atlantic

Year	Station Size (# of Refills/Day)	Capital Recovery Cost ($/GEG)	Energy Costs ($/GEG)	Non-Energy Operating Costs ($/GEG)	Taxes & Retail Markup ($/GEG)	Total Hydrogen Cost ($/GEG)
2020	160	4.35	3.52	1.45	0.00	9.32
2030	58	4.58	3.43	1.53	0.00	9.54
2040	128	3.99	3.35	1.33	0.00	8.68
2050	159	3.90	3.48	1.30	0.00	8.68

Distributed Hydrogen Production and Dispensing Cost Estimates, Commercial Electricity Contiguous Pacific

Year	Station Size (# of Refills/Day)	Capital Recovery Cost ($/GEG)	Energy Costs ($/GEG)	Non-Energy Operating Costs ($/GEG)	Taxes & Retail Markup ($/GEG)	Total Hydrogen Cost ($/GEG)
2020	105	5.51	4.18	1.84	0.00	11.53
2030	68	5.47	4.15	1.82	0.00	11.45
2040	151	4.75	4.14	1.58	0.00	10.47
2050	186	4.64	4.38	1.55	0.00	10.56

Distributed Hydrogen Production and Dispensing Cost Estimates, Commercial Electricity Mountain

Year	Station Size (# of Refills/Day)	Capital Recovery Cost ($/GEG)	Energy Costs ($/GEG)	Non-Energy Operating Costs ($/GEG)	Taxes & Retail Markup ($/GEG)	Total Hydrogen Cost ($/GEG)
2020	52	5.22	3.40	1.74	0.00	10.37
2030	76	4.75	3.29	1.58	0.00	9.63
2040	168	4.12	3.20	1.37	0.00	8.70
2050	208	4.03	3.30	1.34	0.00	8.67

Table A.6 (Cont.)

Distributed Hydrogen Production and Dispensing Cost Estimates, Commercial Electricity West North Central

Year	Station Size (# of Refills/Day)	Capital Recovery Cost ($/GEG)	Energy Costs ($/GEG)	Non-Energy Operating Costs ($/GEG)	Taxes & Retail Markup ($/GEG)	Total Hydrogen Cost ($/GEG)
2020	72	5.36	3.02	1.79	0.00	10.17
2030	52	5.24	2.96	1.74	0.00	9.94
2040	115	4.56	2.92	1.52	0.00	9.00
2050	142	4.46	3.04	1.49	0.00	8.99

Distributed Hydrogen Production and Dispensing Cost Estimates, Commercial Electricity Middle Atlantic

Year	Station Size (# of Refills/Day)	Capital Recovery Cost ($/GEG)	Energy Costs ($/GEG)	Non-Energy Operating Costs ($/GEG)	Taxes & Retail Markup ($/GEG)	Total Hydrogen Cost ($/GEG)
2020	115	5.54	4.36	1.85	0.00	11.75
2030	65	5.59	3.87	1.86	0.00	11.32
2040	145	4.85	3.44	1.61	0.00	9.91
2050	179	4.72	3.25	1.57	0.00	9.54

Table A.7 Distributed Hydrogen Production and Dispensing Using Electrolysis — Summary Results for Selected Regions

Distributed Hydrogen Production and Dispensing Cost Estimates, Commercial Electricity

Region	Year	Total Hydrogen Cost ($/GEG)
New England		
	2010	15.27
	2020	14.13
	2030	13.80
	2040	12.44
	2050	12.35
East North Central		
	2010	9.62
	2020	8.90
	2030	8.69
	2040	7.83
	2050	7.78
East South Central		
	2010	10.23
	2020	9.47
	2030	9.24
	2040	8.33
	2050	8.28
West South Central		
	2010	12.37
	2020	11.45
	2030	11.18
	2040	10.07
	2050	10.01

APPENDIX B: ALTERNATIVE ESTIMATES OF THE COST OF DISTRIBUTED PRODUCTION OF HYDROGEN FROM ELECTROLYSIS

Table B.1 SFA and DTI Estimates of the Cost of Distributed Hydrogen Production from Electrolysis

	Source		
Item	**SFA**	**DTI**	**Comments**
Performance Characteristics:			
Station Design H_2 Production Rate (kg/d)	920	920	SFA rate adjusted to = DTI assumptions
Electrolyzer Direct Cost ($/kWe)	$2,017	$300	
Overall Indirect Capital Cost Factor (percent of direct CC)	63.9%	0%	
Electrolyzer Efficiency	75%	89%	DTI value back-calculated.
Electrolyzer Capacity Factor	70%	69%	
Plant Lifetime (yrs)	n/a	10	
Capital Charge Factor	18.0%	16.8%	DTI value calculated.
Discount Rate	n/a	10.8%	DTI number calculated.
Fixed O&M Cost (% of capital cost)	5.0%	2.50%	
Labor Cost ($/kg)	n/a	$0.76	DTI number calculated.
Non-Fuel O&M Costs (% of capital cost)	1%	n/a	
Corporate Overhead (% of revenue)	n/a	15%	
Capital Costs			
Electrolyzer Direct Capital Cost	**$4,058,186**	**$510,000**	Both models with 920 kW/day H_2 production capacity (= 155 refuelings/day)
Compressor Direct Capital Cost	$273,625	n/a	
H_2 Storage Direct Capital Cost	$209,533	n/a	
H_2 Dispensing Direct Capital Cost	$60,000	n/a	
Total-Compressor + Storage + Dispensing	**$543,158**	**$470,000**	All compressor, storage & dispensing costs combined in DTI report
Indirect Cost Factors (applied to all capital costs)			
General Facilities (% of Direct Cost):	20%	n/a	
Engineering	10%	n/a	
Contingencies	10%	n/a	
Working Capital	9%	n/a	
Regional Factor	10%	n/a	
Overall Indirect Factor	49%		
Regional Cost Factor (on all costs)	14.9%	n/a	
Overall Indirect Factor	63.9%	n/a	
Total Electrolyzer Installed Cost	**$6,651,367**	**$510,000**	
Total Compressor, Storage, Dispensing Cost	**$890,236**	**$470,000**	
Total Electrolysis System Construction/Commissioning Cost	**$7,541,603**	**$980,000**	

APPENDIX C: KEY ASSUMPTIONS IN REGIONAL H_2 MODEL 1.0

Table C.1 presents key assumptions underlying the current version of the Regional H_2 Model. Sources are provided. Where appropriate, estimates of the level of difficulty of changing the assumptions used in the model are also provided. (In some cases, where we think it is most needed, we provide an explanation for the particular estimate.) The level-of-difficulty categories, as shown in the table, are as follows:

- A: Easy to change;
- B: Moderately easy to change;
- C: Difficult, but not impossible, to change; and
- D: Not possible to change.

See the full report for a complete discussion of the assumptions.

Table C.1 Key Assumptions in Regional H_2 Model 1.0

Topic and Topic Number	Key Assumptions	Source	Level of Difficulty in Changing Assumption[a]
H_2 DEMAND (D)			
Total U.S.			
D1	Total FCV penetration based on the following assumptions: 1. FCV sales start in 2015 (except for limited demonstrations). 2. FCV sales reach 50% of light vehicles (LVs) (cars and light trucks [LTs]) by 2035 and plateau there through 2050.	One scenario of a joint DOE/NRCan study (Patterson et al. 2003)	A (assumes use of VISION model developed for DOE/EERE to generate another scenario [Singh, Vyas, and Steiner 2003])
D2	New FCV fuel economy in gasoline gallons equivalent (GGE) is as follows: 1. For cars: Starts at 55.8 MPG (2015) and reaches 80.3 MPG (2050). 2. For LTs: Starts at 41.5 MPG (2015) and reaches 59.7 MPG (2050).	One scenario of a joint DOE/NRCan study (Patterson et al. 2003)	A (assumes use of VISION model developed for DOE/EERE to generate another scenario [Singh, Vyas, and Steiner 2003])
D3	Total light-vehicle annual sales, stock vintaging, on-road fuel economy degradation factor, annual miles of travel, and other parameters are those estimated in the VISION model.	VISION model developed for DOE/EERE (Singh, Vyas, and Steiner 2003)	C (not easy to change the VISION model itself)

Table C.1 (Cont.)

Topic and Topic Number	Key Assumptions	Source	Level of Difficulty in Changing Assumption[a]
By Census Region (with Alaska and Hawaii disaggregated from the Pacific region)			
D4	Total H_2 demand allocated according to year 2000 motor gasoline use for transportation by region.	EIA[b]	B (could input alternative regional demand estimates)
Within Census Region			
D5	Within each U.S. census region, total H_2 demand allocated to metropolitan (metro) areas vs. non-metro areas according to year 2002 LV VMT estimates for those areas.	EPA[c]	B (could input alternative metro vs. non-metro demand estimates)
Over time			
D6	FCV market penetration occurs at the same rate in all U.S. Census regions.	Assumption made by model developers	C/D (would require significant changes in the model)
D7	FCV travel and thus fuel use occurs first in metro areas and gradually expands to non-metro areas (see Table 2.4):	Assumption made by model developers	
	1. By 2020, no non-metro FCV travel except along non-metro interstates (by region).	Assumption made by model developers	C (would require changes to model)
	2. By 2030, FCVs meet 60% of the non-metro travel requirements of the average LV (by region).	Assumption made by model developers	A
	3. By 2040, FCVs meet all of the non-metro travel requirements of the average LV (by region).	Assumption made by model developers	A
H_2 PRODUCTION (P)			
General			
P1	Each Census region will produce sufficient H_2 to meet the region's demand in all years.	Assumption made by model developers	D

Table C.1 (Cont.)

Topic and Topic Number	Key Assumptions	Source	Level of Difficulty in Changing Assumption[a]
P2	Relative resource fuel availability in a region determines the likelihood of each resource being used to produce H_2 in that region:	Assumption made by model developers	
	1. Each region's natural gas, coal, biomass, wind[d], and solar resource fuels individually receive an "availability ranking" according to existing characterizations of the availability of the resources. The biomass, wind, and solar rankings are combined into one renewables ranking. (See Table 3.1.)	EIA, ORNL[e], and NREL[f], data/estimates (EIA 2001, 2002, 2003)	C (would require changes to model)
	2. Each region's nuclear "availability ranking" is based on whether any nuclear plants exist in the region or not. (See Table 3.1.)	EIA[g]	B
Centralized versus distributed production			
P3	Distributed production is used to serve 100% of a FCV's non-metro interstate travel in 2020 and 75% of a FCV's non-metro travel by 2030 and beyond (by region). Centralized production provides all other H_2.	Assumption made by model developers	A
Allocation of regional resource fuels for centralized production			
P4	Natural gas use is phased out by 2050, but has longest use in more highly ranked regions. (See Table 3.5.)	Assumption made by model developers	B
P5	Up to 5% of current electricity sales in a region can be used to produce H_2 ("centralized electrolysis using general utility resource fuel mix") and that amount continues through 2050. (See Table 3.2.)	Assumption made by model developers	B
P6	No more than 30% of a region's H_2 demand in any year can be met by "centralized electrolysis using general utility resource fuel mix," up to the 5% limit in P5.	Assumption made by model developers	B

Table C.1 (Cont.)

Topic and Topic Number	Key Assumptions	Source	Level of Difficulty in Changing Assumption[a]
P7	Thermochemical water splitting using advanced, high-temperature nuclear reactors ("nuclear") will not be in use until 2030. It will meet 1% of the H_2 demand in 2030, 8% in 2040, and 20% in 2050 in regions that have nuclear power and that have a high availability ranking for either coal or renewables. If a region has nuclear power, but is not ranked highly for coal or renewables, it may use 25% more nuclear power than average. In regions with no nuclear plants today, it will not be used.	Assumption made by model developers	C
P8	Once the production of H_2 from natural gas, centralized electrolysis using general utility resource fuel mix, and nuclear is estimated for each region, coal and renewables split the remainder. The split is based on the relative "availability rankings" of these two fuels in each region. (See Table 3.6.)	Assumption made by model developers	B
P9	The renewables are split according to EIA's projected use of these resources for electricity generation and end-use sector energy in 2025. The same split is held throughout the analysis period. (See Table 3.7.)	EIA (2003)	B
Allocation of regional resource fuels used for distributed production			
P10	Both SMR and electrolysis are used for distributed production.	Assumption made by model developers	C
P11	Because SMR is less expensive than electrolysis, SMR will initially be the predominant method of distributed production.	Assumption made by model developers	A
P12	No natural gas will be used for distributed H_2 production by 2050 in any region.	Assumption made by model developers	A

Table C.1 (Cont.)

Topic and Topic Number	Key Assumptions	Source	Level of Difficulty in Changing Assumption[a]
P13	Use of natural gas for distributed production will phase out in different regions at various rates, depending on the region's natural gas "ranking." (See Table 3.4.)	Assumption made by model developers	B
H_2 COSTS (C)			
Centralized production without consideration of regional differences			
C1	Used methodology developed by SFA Pacific, Inc. (SFA), and assumed technological improvements over time for SMR, electrolysis, coal, and biomass.	SFA Pacific, Inc. (2002)	C
C2	For wind, solar, and nuclear production of H_2, costs are based on relationships of these technologies to other technologies.	Assumption made by model developers	C
C3	Assumed carbon sequestration added 20% to cost of producing H_2 from coal.	Assumption made by model developers	A
Regional differences in centralized production			
C4	Use EIA's regional energy cost projections for electricity, coal, and natural gas and extrapolate to 2050.	EIA (2003)	B (could input alternative estimates)
C5	Regional biomass costs derived from state-level biomass supply curves provided by ORNL.	ORNL[h]	C
Delivery costs associated with centralized production			
C6	For delivery of all H_2 centrally produced (except that produced from natural gas), assumed that it would first be delivered by cryogenic tanker and then pipeline (100% by tanker in 2010, 50/50 in 2020, and 100% pipeline by 2030).	Assumption made by model developers	C

Table C.1 (Cont.)

Topic and Topic Number	Key Assumptions	Source	Level of Difficulty in Changing Assumption[a]
C7	For delivery of H_2 centrally produced from natural gas, assumed that it would only be delivered by cryogenic tanker. Because of the phase-out of H_2 production from natural gas in general, H_2 pipelines would not be built from these facilities.	Assumption made by model developers	C
C8	National average H_2 delivery costs using cryogenic tankers derived from SFA. No cost reductions over time.	SFA Pacific, Inc. (2002)	C
C9	National average H_2 delivery costs using pipeline derived from SFA, but extensively modified to reflect cost reductions over time. Modifications assume amortization of older pipeline capital costs, conversions of existing natural gas pipelines and reduction in average shipment transport distances.	SFA Pacific, Inc. (2002)	C
Regional differences in delivery costs associated with centralized production			
C10	Used regional differences in existing pipeline construction costs, existing pipeline operating (electricity) costs, and estimated relative average pipeline lengths from centralized production facilities to metro areas to vary regional pipeline delivery costs. Relative average pipeline lengths based on # of metro areas that have to be served in a region per 10,000 mi^2.	*R.S. Means Construction Cost Estimating Guide* (2002)	C
C11	Used estimated relative average truck distances from centralized production facilities to metro areas to vary regional truck delivery costs. Relative average distances based on number of metro areas that have to be served in a region per 10,000 mi^2.	Assumption made by model developers	C
Dispensing costs associated with centralized production			
C12	Used costs estimates developed by SFA. Assumed cost reductions over time.	SFA Pacific, Inc. (2002)	B

Table C.1 (Cont.)

Topic and Topic Number	Key Assumptions	Source	Level of Difficulty in Changing Assumption[a]
Regional differences in dispensing costs associated with centralized production			
C13	Assumed no regional differences.	Assumption made by model developers	C
Distributed production costs without consideration of regional differences			
C14	Used costs estimates developed by SFA, but modified reformer and electrolyzer efficiency improvements over time. Costs vary by station size.	SFA Pacific, Inc. (2002)	C
Regional differences in distributed production costs			
C15	Because cost depends on volume, particularly for stations using SMR, need to estimate average station size (volume) by region. To do so:		
	1. Assume that eventually there will be the same number of H_2 stations in non-metro areas of the United States as there are gasoline stations now in order to provide adequate geographic coverage. (No need to estimate volumes in metro areas because we assume that for a scenario of substantial H_2 demand [such as the one analyzed here], distributed production is only used in non-metro areas.)	Assumption made by model developers	C
	2. Use Economic Census data to determine the number of gasoline stations in non-metro areas of the United States.	U.S. Census Bureau (2000)	
	3. Given the number of H_2 stations thus estimated, estimate average station volume by region over time by dividing the regional distributed production estimates developed in P3 by these station numbers.	Assumption made by model developers	C
C16	Use EIA's regional energy cost projections for natural gas and electricity and extrapolate to 2050.	EIA (2003)	B (could input alternative estimates)

[a] The levels of difficulty are as follows: A: Easy to change; B: Moderately easy to change; C: Difficult, but not impossible, to change; D: Not possible to change.

[b] Energy Information Administration, "Motor Gasoline Consumption, Price and Expenditure Estimates, 2000," available at http://www.eia.doe.gov/emeu/states/sep_fuel/html/fuel_mg.html#footnotes, accessed Oct. 2003.

Table C.1 (Cont.)

[c] Spreadsheets provided by John Koupal, U.S. Environmental Protection Agency (EPA), August 2004. Also see E.H. Pechan & Associates, Springfield, VA, 2004, "Documentation for the Onroad National Emissions Inventory (NEI) for Base Years 1970-2002," Jan.

[d] http://www.eere.energy.gov/windpoweringamerica/images/windmaps/wherewind800.jpg, wind resource estimates, accessed Oct. 2003.

[e] http://bioenergy.ornl.gov/resourcedata/index.html, Biomass Feedstock Availability in the United States: 1999 State Level Analysis, accessed Oct. 2003.

[f] http://maps.nrel.gov/annualdir.html, solar resource estimates, accessed Oct. 2003.

[g] http://www.eia.doe.gov/emeu/states/sep_sum/html/sum_btu_1.html, Energy Consumption Estimates by Source and End-Use Sector, 2000, accessed October 2003.

[h] http://bioenergy.ornl.gov/resourcedata/index.html, Biomass Feedstock Availability in the United States: 1999 State Level Analysis, accessed Oct. 2003.

Appendix C References

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