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ECONOMICS OF HYDROGEN PRODUCTION

by
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Energy and Environmental Systems Division
Special Projects and Industrial Applications Group

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FOREWORD

Argonne National Laboratory (ANL), in its role as field manager of technical and economic analysis for the Biomass Energy Technology Division (BETD) of the U.S. Department of Energy, was asked to establish a value-based cost goal for research on new methods of hydrogen production. This cost goal is the future price of hydrogen produced by known technology. A new technology must produce hydrogen at a price lower than the cost goal, if the innovation is to be adopted. In response to BETD's request, ANL reviewed existing hydrogen technology and price forecasts for the feedstock and fuel inputs. ANL then projected the price of hydrogen and studied its sensitivity to changes in the input prices. This report presents the results.

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ECONOMICS OF HYDROGEN PRODUCTION

by

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ABSTRACT

Much of the current interest in hydrogen (H_2) centers around its potential to displace oil and gas as a fuel. The results of this study should be useful to research and development managers making funding decisions, and they should also be of interest to energy analysts, economists, and proponents of a "hydrogen economy." We examined the current costs of H_2 produced by commercially available technologies (from fossil fuels and by electrolysis) and projected these costs to 2010, to set cost goals for H_2 produced via new technologies. We also examined the sensitivity of H_2 costs to varying energy price forecasts, capital costs and the required rate of return on investment, and by-product credits. We find that conventionally produced H_2 will not break into the fuel market before 2010.

1 USES AND PRODUCTION OF HYDROGEN

Section 1 of this report describes the current usage pattern and gives production statistics for hydrogen (H_2). Section 2 describes commercially available H_2 production technologies, and Sec. 3 compares the economics of these methods. Section 4 presents conclusions regarding the cost of H_2 and the preferred supply options to the year 2010.

1.1 PROPERTIES AND USES OF HYDROGEN

Hydrogen (H_2) is the lightest of the elements. Its gas density is only 0.0052 lb/scf, a factor of 14 lower than that of air. At atmospheric pressure, H_2 remains a gas down to 20.3 K (-252.9°C). Liquid H_2 is 850 times denser than the gas, but still has a density of only 0.59 lb/gal, a factor of 14 lower than that of water. The critical point is 33.2 K (-240°C) and 13 atm. Hydrogen diffuses rapidly through many materials, including some metals, so it is difficult to store.

Hydrogen can be burned to yield more energy per unit mass (but less per unit volume) than any common fuel. The higher heating value (HHV) is 61,095 Btu/lb (but only 318 Btu/scf) compared to 23,875 Btu/lb (1024 Btu/scf) for methane (see Appendix A).¹ However, hydrogen's major uses are based on its versatility as a chemical reagent. The types of reactions employed, and examples of each, include:

- Synthesis: $N_2 + 3H_2 \rightarrow 2NH_3$ (ammonia synthesis)

- Hydrogenation: $C_6H_6 + 3H_2 \rightarrow C_6H_{12}$ (cyclohexane production)
- Reduction: $C_6H_5NO_2 + 3H_2 \rightarrow C_6H_5NH_2 + 2H_2O$ (aniline production), and
- Desulfurization: $R_2S + 2H_2 \rightarrow 2RH + H_2S$ (R represents any organic group).

The distribution of uses of U.S. H_2 is shown in Fig. 1, where it can be seen that, in 1981, 43% went into the synthesis of ammonia. About 35% was consumed in petroleum refineries to upgrade product streams, and another 14% was used in the production of methanol and other chemicals. Hydrogen is used to a lesser extent in hydrogenation of fats and oils, metal processing, and semiconductor production and as rocket fuel.

In the future, refineries are expected to rapidly increase their H_2 usage per barrel of crude oil, as heavier and higher-sulfur crude oils are treated; however, the total refinery throughput will grow slowly, if at all, and we believe that actual refinery usage of H_2 will only double by 2000. Chemical usage of H_2 will follow the gross national product (GNP), and grow to about 50% more than current levels. Rapid growth is expected in usage by the electronics industry and in any emerging synthetic-fuel industry (at least 10^{12} scf of H_2 is required per 10^{15} Btu [quad] of synfuel produced). After 2010, demand for H_2 as a fuel could grow to as much as 30 times the current total usage, to an annual total of 100×10^{12} scf/yr, or 30 quads. However, except for impure by-product H_2 , the cost of H_2 produced by commercially available methods is expected to remain too high for it to compete with other fuels until well into the next century. The economics of H_2 production are discussed in detail in Sec. 3.

FIGURE 1 How U.S. Hydrogen Was Used in 1981

1.2 PRODUCTION STATISTICS

1.2.1 Domination by Captive Producers

Approximately 3×10^{12} scf (8×10^6 tons) of H_2 is produced annually in the United States. The fuel value (HHV) of this material is approximately 10^{15} Btu (1 quad). There are about 100 producers, with hundreds of plants scattered all over the country, but the largest concentration is in the south central region, where natural gas for feedstock has historically been cheap. Transportation of H_2 is expensive, so over 98% of the H_2 produced in the United States is consumed on site. All large H_2 consumers produce their own, as do some small consumers. This "captive" H_2 is not actually bought or sold, and it has no market price, although the company may assign it a transfer price. There are virtually no imports or exports, and consumption is equal to production. For these reasons, data on production and price are difficult to obtain.

About 1.5%, or 50×10^9 scf/yr, of H_2 is actually purchased as "merchant" H_2 . The three largest producers of merchant hydrogen, and their 1979 production capacities, are: Air Products (13×10^9 scf/yr), Linde (7×10^9 scf/yr), and Airco (1×10^9 scf/yr).² About 31×10^9 scf/yr of merchant H_2 is transported by pipeline, and 12×10^9 scf/yr as liquid in railroad tankcars or truck trailers. Less than 10^9 scf is sold each year in cylinders; the remainder is sold to the government as rocket fuel (undetermined transport method). The price of this H_2 varies widely according to quantity, location, and method of transport. Recent merchant H_2 prices are shown in Table 1.

1.2.2 Proportions of Primary and By-Product Hydrogen Production

About two-thirds of the hydrogen used in the United States is the primary product of a chemical process. The rest is a by-product of processes carried out for

**TABLE 1 Merchant Hydrogen Prices
(Delivered; 1982 dollars)**

Transport Vessel	Phase	Price (\$/10 ³ scf)
Cylinder	Gas	80-150
Tank car	Liquid	15-30
Tube trailer	Gas	14-56
Pipeline	Gas	3.60 ^a

^aRef. 7.

Source: Ref. 8, except as noted.

another purpose. Table 2 shows the approximate quantities of primary and by-product H_2 , by the type of establishment. The quantities vary because of changing demand for ammonia and other chemicals. Because hydrogen is not bought or sold, and in most cases is not even measured, the published data are inconsistent and incomplete. However, data on end products are readily available and were used to calculate implied H_2 production. Primary H_2 is produced for a specific use on site, with the exception of that produced by industrial gas companies for the merchant market.

Data on production of ammonia and methanol³ were coupled with published information on process yields⁴ to infer the amounts of H_2 required for those products. Similarly, production statistics for chlorine and ethylene (including known feedstock and by-product mixes) allow the amount of by-product H_2 to be inferred. Table 3 shows the chemical reactions used to calculate H_2 production. Refinery unit process capacities are published annually⁵, as are "crude runs to still" (total refinery throughput).⁶ The throughput divided by crude capacity implies a capacity factor, which can be used to calculate production from dedicated H_2 units. It can also be coupled with the capacity of catalytic reformers (the major source of by-product H_2) and H_2 production per barrel through a reformer⁷ to give approximate by-product production.

In refineries with dedicated H_2 production capacity, all of the H_2 , both primary and by-product, is used for hydrocracking and hydrotreating processes that upgrade many products and increase gasoline production. Some of the by-product H_2 at simpler refineries that need less H_2 is burned for fuel, because its transport does not pay.

TABLE 2 Hydrogen Production, by Type of Producer (10^{12} scf/yr)

Type of Producer	1982	1981	1980
Primary producers			
Ammonia plants	1.15	1.41	1.46
Petroleum refineries	0.48	0.45	0.42
Methanol plants	0.22	0.26	0.22
Small users ^a	0.05	0.05	0.05
Industrial gas producers	0.04	0.04	0.04
Total primary production	1.9	2.2	2.2
By-product producers			
Olefin producers	0.19±0.02	0.23±0.02	0.22±0.02
Chlorine producers	0.10	0.11	0.12
Petroleum refineries	0.72±0.2	0.70±0.02	0.68±0.2
Total by-product	1.0	1.0	1.0
Total production	2.9	3.2	3.2

^aFat and oil producers, metal processors and fabricators.

TABLE 3 Chemical Reactions Used to Calculate Hydrogen Production

Ammonia Production

Methanol Production

Olefin Production

Hydrogen in a mixture with methane is produced during olefin production; much of this mixture is used to fuel the cracking furnaces. Of the H_2 produced as a by-product of chlorine and caustic soda production, 30% is used by its producer (Dow) as a chemical or as fuel,⁹ 20% is used for ammonia production (this provides feed for 2% of all U.S. ammonia production), and the rest is used to produce hydrogen chloride, is used for fuel, or is vented. About 2% of all by-product H_2 is sold to merchants.

Approximately 6% of by-product H_2 (or 2.5% of total production) is burned as a fuel or vented. As the value of H_2 as a material goes up less will be vented, and fuel users will switch to other fuels so that all H_2 is utilized for its highest-value (chemical) uses. By-product H_2 is cheap (as low as $\$1/10^3$ scf,⁹ or $\$3/10^6$ Btu, compared to $\$2/10^3$ scf or more for primary H_2) and will therefore be used in preference to primary H_2 whenever possible. However, the supply of by-product H_2 is limited by the growth in demand for the primary products. Refinery growth will be slow, and H_2 use per barrel will increase as heavier, higher-sulfur crudes are processed. Therefore, by-product H_2 from refineries will not be available for other uses. Ethylene demand has slowed, and chlorine demand is likely to follow the GNP. In sum, rapid growth in demand for H_2 will have to be satisfied by primary production. Commercially available H_2 production methods are discussed in Sec. 2.

2 COMMERCIALY AVAILABLE HYDROGEN PRODUCTION METHODS

Over 90% of intentionally produced H_2 in the United States is made by steam reforming of methane. Steam reforming of propane accounts for about 2%, and partial oxidation of heavier hydrocarbons, another 2%.⁹ Estimates of the amount of H_2 produced by electrolysis of water range from 1% or less¹ to less than 0.1%.⁹ Less than 1% is produced by dissociation of ammonia, although for some users ammonia (initially produced from H_2) serves as a convenient storage medium for the H_2 . This section describes the production technologies, shown schematically in Fig. 2.

2.1 STEAM REFORMING

Steam reforming for hydrogen production is shown schematically in Fig. 3, as are the primary chemical reactions. First methane or another light hydrocarbon is reformed with steam at 1400-1500°F (760-815°C) in a reactor in the presence of a nickel oxide catalyst.¹⁰ The endothermic reaction, which yields carbon monoxide (CO) and H_2 , is the major energy-consuming step in hydrogen production. Part of the gas feedstock is burned externally to supply process heat. Steam is recovered by cooling the hot reaction products. The product gas leaving the primary reformer contains about 76% H_2 , 12% CO, 10% carbon dioxide (CO_2), and 1.3% methane (CH_4).² The subsequent process steps vary, depending on the final product, as can be seen in Fig. 4. If methanol is to be the final product, no further hydrogen-producing reactions are required, because more than enough H_2 is produced by steam reforming for the required 2:1 volume ratio of H_2 to CO. The additional CO required for methanol synthesis may be obtained by adding CO_2 to the reformer. Synthesis gas from heavier feedstocks is deficient in H_2 ; the deficit can be made up by shifting some of the CO (see below), or by using H_2 from electrolysis or from biological decomposition of wastes. The latter options yield more methanol from the same carbon input and would be used if fossil fuels were scarce.

If methanol is not to be produced, the gas from the reformer is treated with steam over a chromium and iron oxide catalyst in the shift converter, forming CO_2 and more H_2 . This reaction, which is exothermic, is carried out at 650°F (340°C)¹⁰ in a reactor divided into multiple fixed beds to control temperature. After the gas is purified to remove CO and CO_2 -- these compounds are absorbed in circulating amine or hot potassium carbonate solution in a packed or multi-tray absorber -- any remaining CO or CO_2 is converted back to CH_4 in a fixed-bed reactor over a nickel catalyst at 700-800°F (370-425°C).¹⁰ Because this reaction is exothermic, cooling is required if CO_x concentrations are 3% or more.¹¹ The removal of CO is necessary because it is a poison for many catalysts, including those used in ammonia manufacture. The product H_2 is 97-98% pure, and may be further purified cryogenically if it is to be used in the electronics industry.

Alternatively, the hydrogen can be purified by pressure-swing adsorption (PSA). In this process, all of the other components in the gas are adsorbed in a molecular-sieve bed, leaving 99.999% pure H_2 . When one bed is saturated, it is depressurized and purged,

FIGURE 2 Hydrogen Production Routes

while the stream is sent through another bed. Less H_2 is recovered per unit of reformer throughput with pressure-swing adsorption, because only one stage of shift reactors is used and some H_2 is lost in the adsorbent purge. However, the purge stream (composed mainly of carbon oxides) is burned to displace reformer fuel, so the total quantity of fuel plus feedstock is less with pressure-swing adsorption than without.¹² Another distinction is that by-product carbon dioxide can be recovered from a conventional amine stripping system, but not from a pressure-swing adsorption system. A flow chart of the process steps for the two methods is shown in Fig. 5.

FIGURE 3 Hydrogen Production by Steam Reforming (Source: Ref. 10)

FIGURE 4 Production of End Products from Hydrogen. A: Methanol from Methane or Heavier Feedstocks; B: Ammonia or Hydrogen End Product

FIGURE 5 How Hydrogen is Purified (Source: Ref. 7)

Steam reforming plants are generally built on a large scale. The largest plant in the United States produces about 100×10^6 scf/d, or over 30×10^9 scf/yr (about 1% of total U.S. production). The smallest plants, owned by companies like fat and oil manufacturers and metal processors and fabricators, produce as little as 0.3×10^6 scf/d each, but most plants are in the range of $20\text{--}60 \times 10^6$ scf/d.

2.2 PARTIAL OXIDATION

The conventional method for production of H₂ from heavy hydrocarbon feedstocks is called partial oxidation (POX) when the feedstock is oil and gasification when the feedstock is coal. A flow diagram of this process is shown in Fig. 6. The overall chemical reactions are essentially the same as for reforming, except that oxygen (O₂) is required for combustion of a portion of the feedstock, within the process vessel, to

FIGURE 6 Hydrogen Production by Gasification of Coal or Partial Oxidation of Residual Fuel Oil

supply the energy for the endothermic reforming reaction. There are several differences between the reforming and partial oxidation processes, and these are summarized in Table 4. With sulfur-containing feedstocks such as coal or oil, acid gas must be removed by the Selexol, Sulfinol, or Rectisol process, which can selectively remove CO₂ and SO₂.

The proportion of the feed that must be burned depends on the feedstock; about 35% is burned in the case of distillate oil.² The minimum theoretical quantities of fuel and feedstock required for H₂ production by conventional methods are compared in Table 5 to the actual process requirements. The theoretical energy requirement is equal, as it should be, to the product's heat of combustion (about 318 Btu/scf). The table also indicates that, except for coal gasification, for which data were poor, the process efficiency (theoretical energy input divided by actual input) is about 80% for all of the H₂ manufacturing methods.

Partial oxidation or gasification processes can accept any hydrocarbon feed, including biomass. The relative merits of coal and biomass for this purpose are shown in Table 6, where it can be seen that biomass is cleaner, but less dense and available in smaller quantities. In addition, biomass generally contains more moisture and therefore requires more costly feed handling and treating equipment, whereas product gases from

TABLE 4 Comparison of Steam Reforming and Partial Oxidation

Process Characteristic	Steam Reforming	Partial Oxidation
Feedstock	light hydrocarbons	any hydrocarbon
Temperature	650-1000°C (1200-1800°F)	1300-1500°C (2350-2700°F) ^a
Pressure	≤40 atm	13-40 atm
Desulfurization	applied to feed	applied to products
Catalyst	Ni-based	none
Oxygen	none	needed
Heat supply	indirect	direct

^aTemperature may be lower for coal feed.

coal gasification require more cleanup. Coal gasification technology is more developed. These factors imply that gasification of biomass is likely to be somewhat more costly than gasification of coal.

2.3 ELECTROLYSIS

Hydrogen can be produced electrolytically by the decomposition of water into its elements. Oxygen is co-produced, in half the volume but eight times the weight, and may be used by local industry.

The reaction is carried out at 160-195°F (70-90°C) in an aqueous electrolyte, typically a strong base such as sodium or potassium hydroxide in 15-35% solution. Numerous cells, such as those shown in Fig. 7, are arranged together, either in series or in parallel, to form a single "module" of the electrolysis plant. Modules in the United States produce about 10×10^3 scf/d, and up to 50 may be contained in one plant; plant sizes range from 7×10^3 to 500×10^3 scf/d.⁹ A typical electrolysis plant produces 20×10^3 to 100×10^3 scf/d, about 1% of the production of a typical reforming plant. Electrolysis plants as large as 50×10^6 scf/d have been built in countries like Norway and Canada, which have abundant hydroelectric power, and a Canadian manufacturer offers a 20×10^6 scf/d plant as its basic design.¹³ The technology is reliable and convenient and produces H₂ in relatively high purity, 99.8±0.2%. The high purity gave electrolysis a significant advantage over reforming (for certain markets), until the introduction of pressure-swing adsorption.

The total energy required for decomposition of water increases slightly with temperature, as can be seen in Fig. 8. At 25°C, 68 kcal/g·mole of H₂O (0.094 kWh or 320 Btu/scf H₂) is required. However, only part of this energy needs to be supplied in the form of electricity (corresponding to the Gibbs free energy); the rest can be supplied in the form of heat (corresponding to the entropy change). The electricity required decreases from about 0.08 kWh/scf at 0°C to 0.067 kWh/scf at 200°C. Most electrolysis

TABLE 5 Energetics of Hydrogen Production

Characteristic	Process			
	Reforming	Partial Oxidation	Gasi-fication	Electrolysis
Feedstock	Methane (CH_4)	Residual Oil ($\text{CH}_{1.4}$)	Coal ($\text{CH}_{0.8}$) ^a	Water (H_2O)
Fuel	Methane (CH_4)	Residual Oil ($\text{CH}_{1.4}$)	Coal ($\text{CH}_{0.8}$) ^a	Electricity
% H_2 derived from H_2O	50	74	83	100
Theoretical input energy (Btu/scf)				
Stoichiometric (feedstock)	251	239	233	0
Enthalpy of reaction (fuel)	79	80	82	314
Minimum energy (feed plus fuel)	330	319	315	314
Actual input energy (Btu/scf)	410±50	410±50	575±100	380±30 ^b
Efficiency (%)	81	78	55	83 ^b

^a10,720 Btu/lb.

^bIf the primary energy to produce electricity is included, actual input is 1170 Btu/scf of H_2 , for a primary efficiency of 27%.

cells are run well above the minimum voltage to achieve rapid production (the minimum voltage can only be achieved by running the reaction reversibly). The reaction would occur more rapidly at higher temperature for the same voltage, but conventional cells encounter corrosion and electrolyte evaporation problems as the temperature rises. The solid polymer electrolyte, under development by GE, would overcome these problems and therefore require less electricity.

TABLE 6 Relative Merits of Biomass and Coal as Feedstocks for Thermochemical Conversion

Factor	Coal	Biomass
Very long-range supply	Depletable	Renewable
Short-range supply	Up to 100,000 tons/d at favorable sites, so greater economies of scale	Maximum 5400 dry tons/d at best sites; up to 2000 dry tons/d at many sites
Moisture content	Usually about 10%, lignites up to 35%; drying usually not needed	Usually about 50%, drying usually needed or efficiency decreased due to heat loss
Sulfur content	High (1-4%); serious emissions problem; poisons most catalysts	Very low (0.1% or less); no emissions problem; decreased capital cost (no scrubbers)
Nitrogen content	High (1-2%); emissions problem; poisons some catalysts	Very low (0.2% or less); no emissions problem; decreased capital cost (minor)
Ash content	High (usually 10%); handling problems in gasifier and in disposal, contaminates wastewater with toxins, increases equipment wear, decreases carbon conversion	Low (usually 1-2%); decreased handling problems, wastewater contamination, and equipment wear result in decreased capital costs; lower fusion temperature of some ash causes agglomeration
Oxygen content	Low (5-10% usual, but variable); oxygen donor required for gasification limits rate; syngas more concentrated; higher heating value than biomass	High (35-40%); no oxygen donor required so rate not limited by contact; syngas more dilute; more water-soluble organics in wastewater; lower heating value than coal
Structural content	High aromatic content, greater heat content (12,000 Btu/lb), higher CO yield per lb of feed	High carbohydrate content, lower heat content (8500 Btu/lb), lower CO yield per lb of feed, higher H ₂ /CO ratio
Heat capacity	0.25-0.37 cal/(gK), somewhat lower than biomass; less heat required per lb to raise temperature (slight effect compared to biomass on dry basis)	0.30-0.6 cal/(gK) depending on moisture content, somewhat higher than coal on dry basis; requires more heat to raise temperature
Specific gravity	Usually 1.2-1.5, much denser than biomass; requires smaller-volume equipment and less handling; decreased capital costs	Usually 0.4-0.7; low density so very bulky; requires larger equipment and more handling
Reactivity	Low and variable with respect to biomass; slower reactor throughput so increased capital costs; more severe conditions so increased operating costs	Ten times as great as coal; greater throughput so decreased capital costs; milder conditions so decreased operating costs and equipment wear
State of the art	Developed, so more-advanced conversion technologies; commercially available gasification systems, so production experience exists	Undeveloped technology, long dormant; new work done only in past few years, so no fully commercialized gasifiers, except modified coal gasifiers, and little modern production experience

Source: Ref. 14.

FIGURE 7 Electrolysis of Water in Alkaline and in Acid Electrolyte
(Source: Ref. 15)

Real electrolysis cells typically require about 0.112 kWh or 380 Btu/scf of H_2 , and they generate waste heat. On the basis of the ratio of minimum energy required to actual energy input, electrolysis achieves about 84% efficiency. (Here energy required refers to the enthalpy of reaction.) However, the energy required to make the electricity must be counted if *primary* energy efficiency is a concern; in that case, only 27% efficiency is achieved, and we shall see in the next section that this is reflected in the energy cost of electrolysis.

FIGURE 8 Theoretical Electrolysis Voltage vs. Temperature
(Source: Ref. 15)

2.4 DISSOCIATION OF AMMONIA

A gas mixture containing 75 vol % H_2 and 25 vol % nitrogen (N_2) can be produced by decomposition of ammonia (NH_3) into its elements. This mixture can be used instead of pure H_2 in several metal industry applications, including annealing (heat treating), refining, and welding. The total quantity of H_2 supplied in this mixture is 10×10^9 to 25×10^9 scf/yr, or less than 1% of total U.S. consumption.

In this process, liquid NH_3 from a cylinder is vaporized and preheated by heat exchange with the reactor effluent. It enters the electrically heated reactor vessel, where it decomposes. The temperature is 1600–1800°F (870–980°C), and the pressure is approximately 1 atm. The product gas is cooled, scrubbed with water to remove residual NH_3 , and then dried.

Hydrogen from this process is cheaper, but much less pure, than that sold in cylinders or produced by electrolysis. The ammonia serves as a storage medium for H_2 : 1 cylinder of NH_3 replaces 33 cylinders of H_2 .^{16,17} The process is economical on a small scale ($<0.02 \times 10^6$ scf/d mixed gas), and is therefore attractive to small users who do not require pure H_2 . However, industrial gas merchants now offer gas mixtures that precisely meet the users' needs and therefore compete with NH_3 dissociation.

3 ECONOMICS OF HYDROGEN PRODUCTION

3.1 COMPONENTS OF THE TOTAL COST

The total cost of hydrogen production has several important components, discussed in this section. (All costs in this report are expressed in constant 1982 dollars.) These components are summed to give the total costs for H_2 made by each technology studied, from now until 2010, and are compared in Sec. 3.2. The largest contributions to H_2 costs are made by the fuel or feedstock, which dominates the variable costs, and the capital cost, which dominates the fixed costs. Other costs, including labor and maintenance, utilities (excluding process fuel), and property taxes, are relatively unimportant. Process by-products can provide considerable revenues if there is a market for them and can therefore reduce the net cost of H_2 .

3.1.1 Fuel or Feedstock Cost

The quantity of fuel required as feedstock and for process heat to produce one cubic foot of H_2 from fossil fuels or by electrolysis is on the order of 400 Btu (somewhat higher for coal). However, the unit costs for the required energy forms vary widely, from about $\$1.65/10^6$ Btu for coal to about $\$14.50/10^6$ Btu for electricity. Therefore, as can be seen in Table 7, the energy cost for a given quantity of H_2 varies by more than a factor of 5, from $\$1.00/10^3$ scf for the cheapest energy source (coal) to $\$5.50/10^3$ scf for the most expensive (electricity). The high cost of electricity reflects its primary energy costs and the capital intensiveness of power generation. It will be seen that the cost of electricity in the United States dominates the total cost of electrolytic H_2 and keeps it from being competitive with H_2 produced on a large scale from fossil fuels. The competitive situation is different in areas like Quebec, which have cheap hydroelectric power.

The fuel costs cited in Table 7 represent the national average delivered prices paid by industrial users. Large H_2 plants (100×10^6 scf/d) consume as much fuel as 200-MW power plants (e.g., 2,000–3,000 tons of coal per day) and may therefore qualify for utility rates. Energy prices to industry and utilities are within 10% of each other, except for coal; utilities may pay as much as 20% less for coal than industry because delivery by unit trains keeps transport costs to a minimum. National average energy prices were used because our goal was to examine the general question of H_2 economics. Energy prices do, of course, vary considerably from region to region, with oil and gas generally being cheapest on the Gulf Coast. They also vary depending on the size of the user and what type of contracts have been negotiated with suppliers; chemical companies with long-term contracts may still get some gas for under $\$1/10^6$ Btu. The price of new gas will be considerably higher than the average. Because of this variability, the sensitivity of H_2 cost to changes in the fuel costs is examined in Sec. 3.2.

Real fuel costs are expected to increase in the future, and with them the total cost of H_2 production. Several projections of future energy prices have been examined and compared. A brief description of these projections and the methods used to generate them can be found in Appendix B. The NEPP IV (Fig. 9) forecasts¹⁸ for energy prices are

TABLE 7 Feedstock/Fuel Cost for Hydrogen Production

Quantity and Cost	Methane	Resid. Oil	Coal	Electricity
Input Quantity per 10^3 scf H_2	400 scf	0.065 bbl	0.26 ton ^b	112 kWh
Input Energy (10^3 Btu per 10^3 scf H_2)	410±50	410±50	575±100	380±30
Cost (1982 \$)				
per unit of fuel	3.69/ 10^3 scf	30.81/bbl	36.30/ton	0.049/kWh
per 10^6 Btu input ^a	3.60	4.90	1.65	14.36
per 10^3 scf H_2	1.37	1.84	0.95	5.49

^aRef. 18 (NEPP IV).

^bAssuming 22×10^6 Btu per ton of coal.

FIGURE 9 NEPP IV Forecasts of Fuel Prices in the Industrial Market (Based on data from Ref. 15)

produced by the Department of Energy and are representative of those studied. The residual fuel oil price is expected to be approximately the same as that of natural gas. Since the capital cost of a plant to make H_2 from residual oil is higher than that for a natural gas reformer (see below), H_2 from residual oil will not be competitive over the study period, except in refineries where "bottom of the barrel" residual oil is available at a very low price. Coal and electricity prices are expected to rise more slowly than natural gas prices, and so processes based on these energy forms will improve their competitive positions.

3.1.2 Capital Cost

The total capital cost for an H_2 production facility includes the cost of process equipment, steam generating units, oxygen plant (for partial oxidation), office buildings, and land, as well as the working capital. For fossil-based H_2 production, the capital cost increases as the feedstock gets heavier. A partial oxidation facility is larger and more complex than a steam reforming plant. An oxygen plant is required, and the heavier the feedstock, the larger the shift-conversion, carbon dioxide removal, and gas clean-up facilities. As can be seen in Table 8, the cost of a large coal gasification plant is estimated to be almost four times that of a CH_4 reformer, and 40% more than that of a residual-oil POX unit producing the same quantity of H_2 .

TABLE 8 Capital Cost and Capital Charges at Four Charge Factors for a 10^8 scf/d Hydrogen Plant (1982 dollars)

Process	Plant Cost ^a (\$ 10^6)	Capital Charge ^b (\$/ 10^3 scf H_2)			
		5%	10%	15%	20%
CH_4 reforming	70	0.11	0.21	0.32	0.42
POX of residual oil	185	0.29	0.57	0.86	1.13
Coal gasification	255	0.39	0.77	1.16	1.55
H_2O electrolysis	95	0.15	0.29	0.44	0.57

^aIncludes working capital and all necessary plant utilities, including a portion of any utilities shared with other processes.

^bDepreciation plus before-tax return on investment.

The capital cost of water electrolysis is approximately equal to that of CH_4 reforming on this large scale. However, the electrolysis plant is made up of many modules, and so the capital cost per unit of capacity is the same for large and small plants. Reforming, on the other hand, enjoys considerable economies of scale. Below about 10^6 scf/d capacity, capital costs per unit of reforming capacity increase considerably, as can be seen in Fig. 10, where the increase in total cost of H_2 from natural gas as capacity decreases is due entirely to the loss of scale economies. (The figure is based on 1974 data;⁴ it is included only to show the general behavior of cost with scale.)

The capital cost of the production facility is used to determine the contribution of capital to the cost per unit of H_2 produced. The major contributors to the capital cost are depreciation and return on investment. Correctly accounting for the cost of capital is rather complicated; the interested reader is referred to Appendix C. However, in practice the cost of capital can be approximated by a "capital charge factor" (as shown in Table 8) times the total plant cost. The value of this factor depends on the depreciation schedule used and the return on investment. We believe that a 14.8% capital charge factor, corresponding to a 20-year plant life and a 10% discount rate, correctly represents current business practice for new investments.* However, we

FIGURE 10 1974 Hydrogen Prices as a Function of Demand (Source: Ref. 4)

*For old investments, many businesses actually achieve lower capital charge factors, i.e., lower returns.

examined higher and lower factors to study the sensitivity of H_2 costs to this factor. As can be seen in Table 8, the cost of H_2 produced by coal gasification is affected very strongly. It will be seen that coal-based H_2 competes with H_2 from CH_4 only at low capital charge factors.

3.1.3 Other Costs

Several other costs make small contributions to the total cost of H_2 . Utilities, other than the process feedstock or the electricity for electrolysis, contribute less than $\$0.10/10^3$ scf of H_2 . These utilities include electricity, process water, and cooling water. Labor contributes up to $\$0.06/10^3$ scf to the total cost. Maintenance, overhead, insurance, etc. contribute from $\$0.12$ to $\$0.36$, being highest for the most complex process, coal gasification. These small costs are summed in Table 9 for each of the technologies discussed.

3.1.4 By-Product Credits

The by-products of H_2 production from fossil fuels are small quantities of sulfur and, from units performing conventional acid gas removal, substantial quantities of carbon dioxide. For CH_4 reforming, a utility credit is generally allowed for steam recovered during the process. The quantity of steam available is roughly proportional to the excess of feedstock above the 380 Btu/scf minimum. There is thus a tradeoff between feedstock input and steam recovered.

The minute quantity of sulfur removed from natural gas feedstock by activated carbon treatments is not recovered; the sulfur from oil or coal feedstocks in the partial oxidation process is recovered during purification of the product gas. Its value is only

**TABLE 9 Summary of Other than
Capital Costs for Hydrogen
Production (1982 dollars)**

Process	Other Costs (\$/10 ³ scf)
CH_4 reforming	0.21
Partial oxidation of residual oil	0.38
Coal gasification	0.49
Electrolysis	0.29

about \$0.02 per 10^3 scf of H_2 produced from residual oil, or \$0.04 per 10^3 scf of H_2 from coal.

The CO_2 from acid gas removal is generally vented (unless methanol is to be the end product) but is potentially valuable. The value of the CO_2 depends on its distance from a user, because the transportation cost is nontrivial. The Great Plains coal gasification plant is expected to sell its by-product CO_2 at \$1/ 10^3 scf for enhanced oil recovery in the Williston Basin. As can be seen in Table 10, the quantity of CO_2 generated increases from one-fourth of the H_2 volume, given CH_4 feedstock, to equal the H_2 volume, given coal feedstock. If this CO_2 can be sold at \$1/ 10^3 scf, coal gains a considerable advantage (\$0.75/ 10^3 scf) compared to methane, and coal is already the most economical H_2 feedstock. The process designer must choose between CO_2 recovery (e.g., via an amine system) and the higher H_2 purity available with pressure-swing adsorption. The sensitivity of total H_2 cost to by-product CO_2 prices will be discussed in Sec. 3.2.

Partial oxidation processes use oxygen obtained by air separation, which yields nitrogen (N_2) as a by-product. Approximately 0.6 scf of N_2 is produced per scf of H_2 from residual oil, and 2.4 scf of N_2 per scf of H_2 from coal. This can be used as an inert atmosphere in chemical and metallurgical processes, or for enhanced oil recovery. If ammonia is to be the final product, just over half of the by-product N_2 from the POX process is used in the NH_3 synthesis, in place of air. The value of the N_2 will depend on the cost of transporting it to the nearest user. One source estimated the value of N_2 for enhanced oil recovery as 25% of the value of CO_2 for that purpose. If the value of CO_2 is assumed to be \$1/ 10^3 scf, an N_2 credit of \$0.15/ 10^3 scf of H_2 could be expected with residual oil as feedstock, or a credit of \$0.60/ 10^3 scf of H_2 with coal as feedstock.

TABLE 10 Production of Carbon Dioxide By-Product

Process	Net Reaction	Moles CO_2 / mole H_2	CO_2 Credit ^a (1982 \$/ 10^3 scf H_2)
CH_4 reforming	$CH_4 + 2H_2O \rightarrow CO_2 + 4H_2$	0.25	0.25
Partial oxidation of residual oil	$CH_{1.4} + 1.3H_2O + 0.35O_2 \rightarrow CO_2 + 2H_2$	0.50	0.50
Coal gasification	$CH_{0.8} + 0.6H_2O + 0.7O_2 \rightarrow CO_2 + H_2$	1.0	1.00
Electrolysis	$2H_2O \rightarrow 2H_2 + O_2$	0	0

^aAt \$1.00/ 10^3 scf CO_2 ; for H_2 plants without pressure-swing adsorption.

When H_2 is produced by electrolysis of water, oxygen is co-produced at half the volume of H_2 . The current price of O_2 is about $\$1.70/10^3$ scf,¹⁹ so if it can be sold, the net cost of H_2 production is reduced by $\$0.85/10^3$ scf. Although this is a substantial reduction in cost, it is insufficient to make electrolysis competitive for large-scale H_2 production. In addition, because transportation of O_2 is expensive, this by-product does not always find a buyer.

3.2 TOTAL COSTS AND SENSITIVITY

3.2.1 Total Cost of Hydrogen

The total costs of H_2 production by methane reforming, partial oxidation of residual oil, coal gasification, and electrolysis are shown in Fig. 11 for the years 1982 and 2000, based on the NEPP-IV energy price projections in constant 1982 dollars. No credit has been allowed for by-product CO_2 , because it is not now sold. No credit has been allowed for O_2 either, because it cannot always be sold. (The effect of by-product sales on the total cost will be examined later). At a 14.8% capital charge rate, H_2 from CH_4 is least expensive now, and will remain so until about 1998. The cost of H_2 from CH_4 is dominated by the feedstock, whereas the coal process has a large contribution from capital cost. By the year 2000, gas prices are expected to be high enough, relative to coal prices, that coal gasification will become the most economical process. Figure 12 shows how the total H_2 cost from each process increases with time as energy prices rise. Oil is expected never to be the feedstock of choice (except in special situations where unusually cheap residual oil is available).

Electrolytic H_2 is unlikely to be competitive with H_2 from fossil fuels on a large scale as long as electricity is generated using fossil fuels. Decreasing the capital cost would have little effect on the total cost. However, operation at higher temperature or closer to the minimum voltage (which would require a larger plant for the same output) would reduce the electricity cost, which dominates the cost of electrolytic H_2 . Thus, the designer of a new electrolysis plant must make a tradeoff between capital cost and energy cost to minimize the total. Reduction in the cost of electrolytic H_2 would strengthen its dominance for small-scale production and raise the maximum capacity at which it competes with steam reforming to more than 1×10^6 scf/d.

3.2.2 Sensitivity Analysis

This section examines the sensitivity of H_2 costs to variations in the major factor inputs -- energy prices, capital costs, and by-product credits. Table 11 shows how the costs of H_2 produced by each of the technologies studied changes for a given change in each of these parameters. The effect of a capital cost increase depends on the capital charge rate.

FIGURE 11 Components of Hydrogen Costs

FIGURE 12 Projection of Hydrogen Production Costs (Based on NEPP-IV Energy Price Forecasts, Ref. 18)

TABLE 11 Sensitivity of Hydrogen Cost to Varied Input Parameters

Parameter	Increase in Parameter Value	Cost Change (1982 \$/10 ³ scf H ₂)			
		Methane Reforming	Resid. POX	Coal Gasif.	Water Electro.
Fuel/Feedstock Cost	\$1/10 ⁶ Btu	0.41	0.41	0.58	0.38
By-product Credit					
CO ₂ Price	\$1/10 ³ scf CO ₂	-0.25	-0.50	-1.00	0
O ₂ Price	\$1/10 ³ scf O ₂	0	0	0	-0.50
N ₂ Price	\$1/10 ³ scf N ₂	0	-0.62	-2.48	0
Capital Charge Rate	10%	0.21	0.56	0.77	0.29
Plant Capital Cost	\$100,000,000				
CCR = 0.038 ^a		0.27	0.27	0.27	0.27
CCR = 0.10		0.45	0.45	0.45	0.45
CCR = 0.15		0.60	0.60	0.60	0.60
CCR = 0.26		0.94	0.94	0.94	0.94

^aSee Table C.1 for definitions of capital charge rate (CCR) designations.

To facilitate the sensitivity analysis, we defined the "minimum price" of H₂ to be the total cost of H₂ produced by the least expensive conventional method. In Fig. 12, the minimum price is the cost of H₂ from CH₄ reforming until about 2000, at which time the coal gasification cost determines the minimum. (The minimum price is the marginal cost of H₂ from new plants; H₂ from older plants using more expensive feedstocks could cost more. The actual average price, therefore, might be higher than the minimum. Even after old, higher-cost plants are retired, the market price might not go down to the minimum price.)

We will discuss how variation in key parameters affects the minimum price and the least-cost technology. The minimum price will be seen to be more stable, with respect to variations in factor costs, than is the cost of H₂ from any given single technology. This is because the production technology can be changed to one less sensitive to the varied factor, and in that way the minimum price is buffered against large changes in a single factor.

3.2.2.1 Sensitivity to Energy Prices

The fuel or feedstock is the only cost component expected to rise substantially in real terms, and price forecasts made by various agencies differ substantially (see Appendix B). This section examines how the minimum price of H₂ changes for differing

energy price forecasts. The main conclusion is that the minimum price does not vary drastically, because rapid changes in natural gas prices can be buffered by the shift to coal, which sets a bound for the variation because all projections of coal prices are similar. The projected minimum price of H_2 (for 14.8% capital charge rate) under all of the energy price forecasts is shown in Fig. 13. In 2000, the minimum price of H_2 is expected to be about $\$3.00/10^3$ scf on the basis of natural gas prices forecast by Data Resources, Inc.,²⁰ the Gas Research Institute (GRI),²¹ and by DOE in the NEPP IV;¹⁹ it is expected to be about $\$2.30$ on the basis of the considerably lower gas price forecast by the American Gas Association (AGA).²² The results for electrolytic H_2 , which sets a price for small-scale production, are shown in Fig. 14. In this case, the implied H_2 price from AGA's projection is higher than the others because of AGA's high electricity price forecasts.

In addition to comparing forecasts from several sources, we examined different scenarios from the Energy Information Administration (EIA).²³ Under EIA's "High World Oil Price" scenario, coal simply becomes the least-cost feedstock three years sooner, displacing gas by 1986.

We examined the competition among conventional H_2 production technologies when the price of a single energy input was varied with respect to the others. In Fig. 15, the price of residual fuel oil is decreased by $\$3.50/10^6$ Btu from that forecast by the NEPP IV,¹⁸ to see the effect of very low-price feedstock, as might be available in a refinery, for partial oxidation. In Fig. 16, the electricity price is dropped to the marginal cost of coal for electricity generation to simulate a locale with cheap hydroelectric or nuclear power. Cheap feedstock makes partial oxidation the least-cost technology, but electricity prices must be even lower to improve the competitive position of electrolysis for large-scale H_2 production.

3.2.2.2 Sensitivity to Capital Costs

The capital costs of H_2 production technologies are not well known. We therefore examined the sensitivity of H_2 cost to the capital cost of the plant. As an example, the estimated capital cost for coal gasification is raised by $\$100 \times 10^6$, or 40%. The results are shown in Fig. 17, where it can be seen that coal is still the least-cost technology by 2003, but the minimum H_2 cost is raised by about $\$0.60$, to $\$3.75/10^3$ scf, in 2010.

The minimum cost of H_2 between now and 2010 is shown in Fig. 18 for capital charge rates of 3.8% (very low), 10% (low), 15% (medium), and 20% (high). Lowering the capital charge rate lowers the total costs of H_2 from coal and brings nearer the time when coal will be the least-cost method for large-scale production, from about 1998 for a 15% capital charge rate to 1989 for 3.8%. The total cost of 10^3 scf of H_2 in 2010 is lowered from about $\$3.15$ to $\$2.25$ if the capital charge rate is lowered from 15% to 3.8%. This decrease roughly corresponds to the difference between the rate of return companies expect on investments and the return they actually achieve.

FIGURE 13 Cost of Hydrogen Produced by the Lowest-Cost Conventional Production Method, under Different Fuel-Price Projections (Based on data from Refs. 6, 18, 21-23)

FIGURE 14 Cost of Electrolytic Hydrogen under Different Fuel-Price Projections (Based on data from Refs. 6, 18, 21-23)

FIGURE 15 Sensitivity of Hydrogen Cost to Price of Residual Oil

FIGURE 16 Sensitivity of Hydrogen Cost to Electricity Price

FIGURE 17 Sensitivity of Hydrogen Cost to Capital Cost of a Coal Gasification Plant

FIGURE 18 Minimum Price of Hydrogen at Different Capital Charge Rates

3.2.2.3 Sensitivity to By-product Credits

Credit for the by-product sulfur from partial oxidation is too small to influence overall H_2 economics. Credit for O_2 from electrolysis is substantial (about $\$0.85/10^3$ scf of H_2) but smaller than the price difference between electrolytic and fossil-based H_2 . It will therefore influence only decisions among small-scale production options, favoring electrolysis if a local buyer for the O_2 can be found.

The by-product of H_2 production that has considerable potential for affecting the overall economics is CO_2 from fossil-based processes. Although this CO_2 is vented at present, up to $\$2/10^3$ scf is now being spent to recover CO_2 from power plants near oil fields. When the Great Plains gasification plant goes into service, recovered CO_2 will be sold at $\$1/10^3$ scf and shipped by pipeline for enhanced oil recovery. The revenue from the CO_2 depends on the transportation cost, so plant location relative to potential users is important in determining the CO_2 by-product credit. Figure 19 shows that coal is the least-cost feed for H_2 production now, if the CO_2 can be sold at $\$1/10^3$ scf. Thus, sale of the CO_2 by-product would significantly reduce the cost of H_2 from coal.

FIGURE 19 Minimum Hydrogen Price with Carbon Dioxide Credit

4 CONCLUSIONS

We projected the cost of H_2 produced by conventional methods to the year 2010. For large-scale production, steam reforming of methane will remain the least-cost method until about 2000, when coal gasification is expected to displace it because of relatively slower-rising coal prices. The cost of H_2 will be about $\$3/10^3$ scf ($\$9.30/10^6$ Btu) in 2000, and $\$3.15/10^3$ scf ($\$9.60/10^6$ Btu) in 2010, both calculated for a 14.8% capital charge rate. Any new technology must meet these costs to be competitive in the major H_2 markets.

The projected cost is sensitive to several parameters. Variations in the price of fuel or feedstock within the range defined by the forecasts could lead to as much variation as $\$0.50/10^3$ scf in the year-2000 price of H_2 . An increase of 10% in the required capital charge rate (to 25%) would raise the H_2 price by $\$0.40$; a 10% decrease would lower it by $\$0.80$; and sale of the by-product CO_2 for $\$1/10^3$ scf would lower the price by about $\$1.00$. Thus, even substantial changes in any of the factor inputs to H_2 cost lead to changes of $\$1/10^3$ scf or less for the total. The price of H_2 in 2010 is therefore very likely to be between $\$2.50$ and $\$5/10^3$ scf ($\$8$ – $\$15/10^6$ Btu).

New technologies for production of H_2 on a small scale must be competitive with electrolysis, which is expected to produce H_2 at $\$7.90/10^3$ scf, or $\$24/10^6$ Btu (with no O_2 credit) in 2000. Hydrogen produced at this price could compete with merchant H_2 and would also be used by small users producing their own H_2 . These two market segments total about 100×10^9 scf/yr, a heating value of about 0.03 quad, or 3% of all U.S. H_2 consumption.

The final question is, "Will hydrogen compete in the fuel market?" It will compete if and when the delivered cost of hydrogen is less than that of other natural and synthetic fuels, assuming similar end-use technologies. Hydrogen is already cheaper than electricity (on a delivered-heat basis), but is not capturing its market because the efficient end-use technologies of electricity provide goods and services at low total cost. Although hydrogen is projected to cost three times as much as coal in 2010, the total cost of raising steam (the principal use of coal) with hydrogen might be less than with coal. However, synthesis gas or methane also would compete for this market. Arguments about the competitiveness of H_2 with oil and methane apply to both natural and synthetic fuels. Methane is projected to remain less expensive than distillates and approximately equal in price to residual fuel oil for all sectors, and is likely to take over markets as the stock of oil-burning equipment is retired. Hydrogen must therefore compete with methane if it is to capture fuel markets.

The cost of distributing hydrogen in large quantities is not well known, but it is certainly greater than the cost of distributing methane (hydrogen has a lower energy density, so either three times the volume of gas must be transported or the pressure must be raised). A hydrogen plant can be located just outside the city (the feedstock prices we analyzed include delivery), equivalent to the "city gate" where methane distribution systems begin. Hydrogen must be cheaper than methane at the city gate to merit further consideration. These costs are compared in Table 12 for 2000 and beyond; different energy price projections are considered. Only in the case of the NEPP projection for

TABLE 12 Approximate Costs of Hydrogen and Methane before Distribution, 2000 and Beyond (1982 \$)

Energy Projection	Year	Cost (\$/10 ⁶ Btu)	
		H ₂ at Plant	City-Gate ^a Methane
NEPP	2000	9.59	7.16
	2005	9.72	9.24
	2010	10.01	10.43
DRI	2000	9.87	5.95
	2005	10.22	6.76
GRI	2000	10.94	6.24
AGA	2000	8.43	4.88

^aAn average transmission cost of \$0.42/10⁶ Btu was added to the acquisition cost.

2010 is hydrogen cheaper than city-gate gas. (This is because of the high projected price of gas relative to coal in that projection.) The difference is about 50% of the minimum distribution cost of gas -- that to industrial customers. Therefore, if the NEPP price projections hold, hydrogen can compete with methane for industrial users in 2010 if the distribution costs for hydrogen are less than 50% higher than the distribution costs for methane. Hydrogen would compete at a later date in other markets with higher distribution costs. We believe that the cost of distributing hydrogen could be as much as three times the cost of distributing methane, and so widespread use of hydrogen as a fuel would not begin until after 2010.

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APPENDIX A:
CONVERSION FACTORS AND HEATS OF COMBUSTION

TABLE A.1 Conversion Factors

Multiply	By	To Obtain
barrels (bbl)	42.0	gallons (gal)
British thermal units (Btu)	1055.0	joules (J)
Btu per pound (Btu/lb)	0.0023	kilojoules per gram (kJ/g)
degrees Celsius (°C)	1.8, then add 32	degrees Fahrenheit (°F)
°F - 32	0.55	°C
cubic feet (ft ³)	28.3	(liter) L
gal	3.78	L
kilocalories (kcal)	4186.8	J
kilowatt hours, electric (kWhe)	10,500	Btu ^a
pound (lb)	0.4536	kilograms (kg)
pound of H ₂	192	standard ft ³ (scf) ^b of H ₂
pounds per square inch (psi)	0.068	atmospheres (atm)
quads	10 ¹⁵	Btu
standard cubic feet (scf) ^b of H ₂	0.02628	normal cubic meters (Nm ³) ^b of H ₂

^aThirty-three percent conversion efficiency assumed.

^bStandard cubic feet are defined at 70°F, 1 atm; normal cubic meters are defined at 0°C, 1 atm.

TABLE A.2 Heats of Combustion (HHV)

Fuel	Unit	Btu/Unit	10 ³ Btu/lb
Hydrogen	scf	318	61
Methane	scf	1.02 x 10 ³	24
Residual fuel oil	bbl	6.3 x 10 ⁶	18
Coal	ton	22 x 10 ⁶	11

APPENDIX B:
ENERGY PRICE FORECASTS

ENERGY PRICE FORECASTS

B.1 SOURCES OF FORECASTS

Energy price projections are developed by many organizations, including government agencies, consulting firms, research organizations, and large corporations. We compared several publicly available forecasts that are representative of the type of results published. Two DOE forecasts are published: one by the Energy Information Administration (EIA)¹ and the other, in the National Energy Policy Plan (NEPP), by the Office of Policy, Planning, and Analysis.² Data Resources, Inc. (DRI) is a major consulting firm whose forecasts,³ available only by subscription, form the basis for those of the Gas Research Institute (GRI).⁴ The American Gas Association (AGA) prepares forecasts⁵ to serve natural gas utility companies. These various organizations each use somewhat different methods and assumptions to prepare their forecasts, as summarized in Table B.1, and the results differ accordingly.

B.2 ENERGY PRICES, 1980-2010

Prices forecast by any source change with time and economic conditions and particularly with world oil prices. (These variations are discussed in detail in a recent DOE publication.²) We examined the most recently published forecasts, with the recognition that they, too, are subject to change. Of the several scenarios offered to reflect possible world oil price paths, the middle (most likely) scenarios, with average U.S. prices, were selected for comparison in this study. Price forecasts are available for utility, industrial, residential, and commercial markets; we chose to base this study on the industrial prices, although the very largest H₂ production plants might qualify for utility prices (e.g., for unit trains of coal).

Forecasts of most likely average industrial energy prices (including taxes), in 1982 dollars, are summarized in Table B.2. Several similarities and differences are apparent among the forecasts. There is fairly good agreement concerning coal and electricity prices. On a per-Btu basis (used throughout), coal will remain the cheapest energy source and electricity the most costly. The difference will increase in real dollars, but the price of electricity will become a smaller multiple of the price of coal. Within any one forecast, the price of natural gas is similar (within 20%) to that of residual fuel oil, but in some cases it is higher, and in others lower.

The price of oil and gas forecast in the NEPP is as much as 50% more than that forecast by DRI, GRI, and AGA. This is the most significant difference among the projections, and affects the date at which natural gas will become no longer the most economical feedstock. The ratio of the real price in 2005 to the current price for each energy source is shown in Table B.3 (along with the implied annual percentage changes) for the DRI and NEPP forecasts. This table demonstrates the uncertainty in future oil and gas prices. It is worth quoting from the NEPP report² that "no model can predict the future." What is important is to have a self-consistent set of energy price projections against which all new supply technologies can be measured and compared.

TABLE B.1 Forecast Cases, Methods, and Assumptions

Forecast and Case ^a	Forecasting Method	Assumptions ^b
DRI(83); Trend Case	Based on DRI's Trendlong macroeconomic model in combination with drilling, coal, and electricity-supply models.	Oil prices return to \$30/bbl by 1990; grow at 3.7% in 1990s. GNP growth = 3.4%, 1982-90; 2.4%, 1990-2000.
EIA(83); Middle World Oil-Price Case	Based on EIA's Long-Term Energy Analysis Program (LEAP) model. Lagged market adjustment mechanism.	Price of oil declines through mid-1980s, then increases. GNP growth = 3.2%, 1982-90.
AGA(83); Base Case	Developed by AGA's Total Energy Resources (TERA) simulation model. Economic activity based on Wharton annual model forecasts.	OPEC price = \$28 bbl in 1983-4, rises 1% in 1985, and 2%/yr to 2000.
GRI(83); Baseline Projection	Method incorporates DRI energy model, GRI supply curves, and the Industrial Fuel Choice Model (IFCAM) of Energy and Environmental Analysis, Inc. (Arlington, Va.)	Oil prices return to \$30/bbl by 1985; increase at 2%/yr, 1986-2000. GNP growth = 2.9%, 1981-2000
NEPP(83); Midrange	Based on DOE's WOIL computer simulation model.	GNP growth = 3.4%, 1982-1990; 2.3% thereafter.

^aDRI(83): Ref. 3; EIA(83): Ref. 1; AGA(83): Ref. 5; GRI(83): Ref. 4; NEPP(83): Ref. 2.

^bAssumptions refer to oil prices and GNP expressed in real (constant-dollar) terms.

TABLE B.2 Projected Industrial Energy Prices (1982 \$/10⁶ Btu)

Energy Form and Projection ^a	1980	1982	1985	1990	1995	2000	2005	2010
Gas								
EIA	2.90	3.87 ^d	5.62	7.23	-	-	-	-
NEPP	2.74	3.60	4.35	4.91	5.83	7.87	10.06	11.32
DRI	-	3.86	4.15	4.81	5.96	6.93	7.82	-
GRI	-	3.88	-	5.33	-	7.17	-	-
AGA	-	4.05	4.50	3.99	4.69	5.20	-	-
Residual oil								
EIA ^b	3.30	3.94	4.19	6.49	-	-	-	-
NEPP	4.45	4.90	4.30	5.43	7.71	9.40	11.71	13.47
DRI	-	4.63	3.99	4.56	5.53	6.49	7.12	-
GRI	-	4.64	-	5.43	-	7.15	-	-
AGA	-	4.39	3.86	4.74	5.15	5.63	-	-
Coal								
EIA	1.55	-	2.10	2.33	-	-	-	-
NEPP	1.55	1.65	1.97	2.16	2.28	2.43	2.50	2.63
DRI ^c	-	1.75	1.80	2.29	2.49	2.59	2.77	-
GRI	-	1.86	-	2.45	-	3.20	-	-
AGA	-	1.71	1.80	1.97	2.30	2.69	-	-
Electricity								
EIA	11.67	14.50 ^d	14.15	15.35	-	-	-	-
NEPP	12.54	14.51	14.51	16.13	18.52	19.03	19.79	19.54
DRI	-	13.65	14.91	16.50	17.33	18.72	20.99	-
GRI	-	13.54	-	17.78	-	20.68	-	-
AGA	-	13.50	16.31	17.91	19.36	21.50	-	-

^aEIA: Ref. 1; NEPP: Ref. 2; DRI: Ref. 3; GRI: Ref. 4; AGA: Ref. 5.

^bHigh-sulfur oil.

^cNew contract price.

^dWholesale prices, Ref 6.

TABLE B.3 Real Price Ratios, 2005/1982

Energy Source	<u>Price Ratio</u>		<u>Annual % Change</u>	
	DRI	NEPP	DRI	NEPP
Natural gas	2.03	2.79	3.1	4.6
Residual oil	1.54	2.39	1.9	3.9
Coal	1.58	1.52	2.0	1.8
Electricity	1.54	1.36	1.9	1.3

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APPENDIX C:
THE CAPITAL CHARGE RATE

THE CAPITAL CHARGE RATE

This appendix explains how we estimated the price that would have to be charged for hydrogen. Our explanation emphasizes two topics -- the federal income tax and the possibility of alternative investments as embodied by the discount rate. Both must be understood to estimate the price of any product of commerce.

The discussion that follows is divided into two parts. The first concerns the relation between the price of hydrogen and the costs incurred by producing and selling it in any single year. The second part describes how we averaged or levelized two of these costs -- the corporate income tax and the funds set aside for investors -- over the life of the hydrogen-producing facility.

C.1 PROJECTED PRICE AND ANNUAL COSTS

The revenue from any business is divided among its investors, its workers, its suppliers, and the government. Disbursements for items that are consumed within a year of their purchase are called expenses, E . Such items include wages, feedstock, fuel, parts purchased for maintenance, insurance, and property taxes. Funds are also set aside for the investors, FFI -- "funds for investors" -- and the federal corporate income tax, IT , must be paid. We express this division of revenue R , in year y , by writing

$$R(y) = E(y) + IT(y) + FFI(y). \quad (C.1)$$

The corporate income tax, IT , is reckoned as follows

$$IT(y) = r_t [R(y) - E(y) - Kf_d i_d - D_t(y)] \quad (C.2)$$

where r_t is the tax rate, D_t is a deduction, called tax depreciation and described later, and $Kf_d i_d$ is the interest paid to bondholders (K is the total capital invested in the project, f_d is the debt fraction, and i_d is the interest rate on debt). The revenue that the project must generate may be found by substituting Eq. C.2 into Eq. C.1.

$$R(y) = E(y) + \frac{r_t}{1 - r_t} [FFI(y) - Kf_d i_d - D_t(y)] + FFI(y) \quad (C.3)$$

To raise this revenue, a business sells its product (hydrogen) and by-products (e.g., carbon dioxide). We assumed that the same quantity of hydrogen, Q_H , and by-product, Q_{bp} , would be produced and sold in each year, and that the price of the by-product, P_{bp} , would not change during the life of the facility. Thus the revenue, $R(y)$, raised in each year by the sale of products is:

$$R(y) = P_H(y) Q_H + P_{bp} Q_{bp}. \quad (C.4)$$

For this revenue to cover the costs incurred in the same year, the price of hydrogen, $P_H(y)$, must be set by substituting Eq. C.4 into Eq. C.3, with the following result:

$$P_H(y) = -P_{bp}(Q_{bp}/Q_H) + [E(y)/Q_H] + \frac{1}{Q_H} \left(\frac{r_t}{1 - r_t} [FFI(y) - Kf_d i_d - D_t(y)] + FFI(y) \right) \quad (C.5)$$

As discussed in Sec. 3 and Appendix B, the cost of feedstock and fuel per unit of hydrogen output is the largest expense, and this expense is projected to rise in real terms. We assumed that the sum of all other costs would remain the same (in real dollars) as they are today. Thus our projections for the price of hydrogen (see Sec. 3) were made by "passing through" the projected increases in the cost of feedstock and fuel and by holding the sum of all other annual costs (in real dollars) to what it would be today.

C.2 LEVELIZED PAYMENTS TO THE INVESTORS AND THE IRS

Although the sum of the funds set aside for investors, FFI, and the corporate income tax, IT, can be assumed to remain the same, the separate payments will vary. In practice, the income tax is smaller in earlier years of the facility's life than in later years and the funds set aside for investors are correspondingly larger in earlier years than in later ones. This pattern occurs because the IRS allows larger tax deductions in earlier years than in later years -- a practice called "accelerated depreciation". Instead of charting each year's allocation of revenue, we followed the common practice of defining equivalent constant or level annual payments to the investors and to the IRS. This subsection explains what we did.

We began with the funds set aside for investors. To induce investors to provide the necessary initial capital, a project must promise them a later stream of funds, $FFI(y)$, whose discounted value is equal to (or greater than) the initial capital, K . Thus we write

$$K = \sum_{y=1}^{T_e} \frac{FFI(y)}{(1 + d)^y} \quad (C.6)$$

where T_e is the economic life of the project (e.g., 20 years), and the discount rate, d , is the annual return an investor would realize on alternative investments. As we noted, $FFI(y)$ decreases as the years go by. We define the "levelized funds for investors", $LFFI$, by requiring that it have the same discounted value as the actual funds set aside for investors. This level payment is

$$LFFI = K \frac{d}{1 - (1 + d)^{-T_e}} \equiv K \cdot CRF(d, T_e) \quad (C.7)$$

The second factor on the right hand side is called the "capital recovery factor" and is denoted by $CRF(d, T_e)$. The "levelized funds for investors," LFFI, can best be understood as the sum of two terms

$$LFFI = K \cdot CRF(d, T_e) = K(1 + d) \overset{\text{economic}}{\underset{\text{depreciation}}{e^{-T_e}}} \cdot CRF(d, T_e) + Kd \overset{\text{return on}}{\underset{\text{investment}}{}} \quad (C.8)$$

The first term, "economic depreciation", represents funds set aside to compensate for the capital equipment's assumed lack of salvage value. When the capital retains its initial value, it can be sold at the end of the facility's life, at which time the additional revenue will cover the cost of economic depreciation. In that case, economic depreciation can be omitted from LFFI because it will not affect the price of the product (i.e., hydrogen). The second term, "return on investment", is what investors receive in addition to the funds initially invested. For a project of average profitability, this return is the product of the discount rate, d , and the capital invested, K . We followed standard practice by dividing the capital spending into three categories: inside battery limits, K_{ISBL} ,* outside battery limits, K_{OSBL} ,* and working capital, K_{WC} . We also followed standard practice by assuming that working capital (e.g., inventory) retained its initial value while all other capital equipment had no salvage value or was fully depreciated. Thus we used, for the "level funds for investors" in our estimates of the price of hydrogen, the following expression:

$$LFFI = (K_{ISBL} + K_{OSBL})(1 + d) \overset{-T_e}{e} CRF(d, T_e) + (K_{ISBL} + K_{OSBL} + K_{WC})d \quad (C.9)$$

To calculate the level income tax payment whose discounted value is equal to the discounted value of the actual income tax payments, one finds the level tax deduction, LD_t , that is equivalent to the sequence of actual tax deductions, $D_t(y)$, (i.e., tax depreciation schedules). A deduction, $D_t(y)$, can be taken for each piece of capital equipment in each year of its tax life, T_t . The sum of all deductions equals the equipment's initial cost. After taking account of the interest that can be earned on the money that was deducted, one finds that more money can be deducted than is required for economic depreciation. To maximize this effect, businesses use tax depreciation schedules that allow large deductions in early years. We have followed them by adopting a currently used accelerated depreciation schedule (150% declining balance with switchover to straight-line) for our cost estimates. We also followed standard practice by assigning a 5-year tax life to ISBL equipment and a 10-year tax life to OSBL equipment (the latter is really a mixture of property with 5- and 15-year tax lives). Since working capital is assumed to retain its original value, we did not depreciate it.

*"Inside battery limits" includes all the capital equipment specifically dedicated to producing H_2 ; "outside battery limits" includes, e.g., buildings, supporting utilities, and ancillary equipment that might also serve other processes besides H_2 production.

These considerations led us to use the following expression for LD_t in our estimates of the cost of hydrogen:

$$LD_t = CRF(d, T_e) \left\{ K_{ISBL} \left[\frac{\alpha_1}{1 - \alpha_1} \frac{f_1 - f_1^{(y_1+1)}}{1 - f_1} + \frac{f_1^{y_1}}{T_1 - y_1} \frac{1}{CRF(d, T_1 - y_1)} \right] + K_{OSBL} \left[\frac{\alpha_2}{1 - \alpha_2} \frac{f_2 - f_2^{(y_2+1)}}{1 - f_2} + \frac{f_2^{y_2}}{T_2 - y_2} \frac{1}{CRF(d, T_2 - y_2)} \right] \right\} \quad (C.10)$$

where:

$$T_1 = 5 \text{ years}$$

$$y_1 = 2 \text{ years}$$

$$\alpha_1 = \frac{1.5}{T_1}$$

$$f_1 = \frac{1 - \alpha_1}{1 + d}$$

$$T_2 = 10 \text{ years}$$

$$y_2 = 4 \text{ years}$$

$$\alpha_2 = \frac{1.5}{T_2}$$

$$f_2 = \frac{1 - \alpha_2}{1 + d}$$

We computed the contribution of capital charges to the price of hydrogen by substituting LFFI (see Eq. C.9) and LD_t (see Eq. C.10) for FFI and D_t in Eq. C.5.

The contribution to price made by the funds set aside for investors and the federal income tax is often expressed as the product of two factors. The first is the ratio of total capital to annual output; e.g., this ratio for methane steam reforming is $\$70 \times 10^6 / (3.3 \times 10^{10} \text{ scf/yr})$, or $\$2.12 \cdot \text{yr} / 10^3 \text{ scf}$. The second factor expresses all the financial assumptions made above. We call that factor the capital charge rate, often expressed in %/yr. Its value depends on the technology, because each technology has different proportions of ISBL, OSBL, and working capital. However, the capital charge rate for each of the four technologies discussed in this report is well approximated by the numbers in Table C.1. These were computed by assuming 100% equity financing (i.e., $f_d = 0$ in Eq. C.5) and using the present tax rate ($r_t = 0.46$). The effect of debt on price is calculated by subtracting from the price 85% of the ratio of total annual interest paid to annual production.

TABLE C.1 Annual Capital Charge Rate (CCR)^a as a Function of Plant Life and Annual Discount Rate

Economic Life of Plant (yr)	CCR per yr, by Annual Discount Rate				
	0.01	0.05	0.07	0.10	0.15
10	0.100	0.14	0.16	0.20	0.26 ^b
20	0.045	0.09	0.11	0.15 ^b	0.22
30	0.038 ^b	0.08	0.10 ^b	0.14	0.21

^aCapital charge rate includes effects of depreciation, return on investment, and U.S. corporate income tax. Not included are certain expenses that are related to capital; see Table 1.

^bCapital charge rate designations used in Table 11 and Fig. 17: 0.26 = high, 0.15 = medium, 0.10 = low, and 0.038 = very low.

APPENDIX D:
SOURCES OF COST ESTIMATES

SOURCES OF COST ESTIMATES

D.1 FUEL AND FEEDSTOCK COST

This cost is equal to the price of the feedstock or fuel, multiplied by the quantity needed. As discussed in Appendix B, energy prices were obtained from several readily available forecasts. The quantity of energy required for each hydrogen-producing process was estimated by comparing data in the open literature¹⁻⁷ and supplementing it with information from industry sources.^{8,9} There was approximately a 20% difference between high and low estimates of specific fuel/feed consumption. Steam reforming was the process best represented in the data, because it is in widespread use; data for the other processes, however, showed similar variation.

D.2. CAPITAL COSTS

The contribution of capital to the cost of H_2 depends on the capital charge rate (CCR, see Appendix C), and the total cost of the plant. We found that firms expected high returns on new investments^{4,7} (corresponding to the highest CCR we considered), but often achieved much lower returns (corresponding to our lowest CCR).

As a first estimate for the total capital costs of hydrogen-production plants (including oxygen plants), we used data prepared in the late 1970s for Exxon by Chem Systems, Inc.⁴ These data have the advantage of having been prepared on the same basis for each technology. However, they are somewhat out of date, and were supplemented with more current information. Chem Systems⁸ provided the information that their estimated 1980 dollars were nearly equivalent to 1982 dollars because plant costs escalated more slowly than they had expected. They also gave guidelines for the costs of a pressure-swing adsorption unit: add 10% to the capital cost and subtract 10% from the cost of fuel for the reformer. They provided current costs for a large-scale coal gasification plant (500×10^6 scf/d), and estimated 0.8-0.9 as the scale factor down to 100×10^6 scf/d, our reference size. In addition, they provided a comparison of capital costs for methanol production from partial oxidation of residual oil and from coal gasification, which enabled us to revise our cost estimate for partial oxidation. Capital costs were provided or implied in several other literature sources^{2,3,5-7} and by an industry contact;⁹ all of these sources were compared and used to construct our best capital cost estimates.

D.3 OTHER COSTS

Quantities of other utilities, such as process water, cooling water, labor required, maintenance, overhead, and property taxes as a function of capital cost were all taken from the original Chem Systems data.⁴ Current prices for other utilities, and current rates for each type of labor required, were taken from a recent prospectus¹⁰ offering current and projected cost data. Capital costs described above were used to determine maintenance, etc.

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