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Electrolytic Hydrogen Production Infrastructure Options Evaluation

Final Subcontract Report

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Abstract

Fuel-cell electric vehicles have the potential to provide the range, acceleration, rapid refueling times, and other creature comforts associated with gasoline-powered vehicles, but with virtually no environmental degradation. To achieve this potential, society will have to develop the necessary infrastructure to supply hydrogen to the fuel-cell vehicles. Hydrogen could be stored directly on the vehicle, or it could be derived from methanol or other hydrocarbon fuels by on-board chemical reformation. This infrastructure analysis assumes high-pressure (5,000 psi) hydrogen on-board storage.

This study evaluates one approach to providing hydrogen fuel: the electrolysis of water using off-peak electricity. Other contractors at Princeton University and Oak Ridge National Laboratory are investigating the feasibility of producing hydrogen by steam reforming natural gas, probably the least expensive hydrogen infrastructure alternative for large markets. Electrolytic hydrogen is a possible short-term transition strategy to provide relatively inexpensive hydrogen before there are enough fuel-cell vehicles to justify building large natural gas reforming facilities.

In this study, we estimate the necessary price of off-peak electricity that would make electrolytic hydrogen costs competitive with gasoline on a per-mile basis, assuming that the electrolyzer systems are manufactured in relatively high volumes compared to current production. We then compare this off-peak electricity price goal with actual current utility residential prices across the United States.

Contents

List of Tables

List of Figures

Metric Conversions

The following conversion table is included for the purpose of converting English units to metric units.

1 ton = 907.18 kg

1 pound = 0.45 kg

1 gallon = 3.79 liters

1 mile = 1609.35 meters

1 mph = 1.61 kph

1 psi = 6895 Pa

1 ft^3 = 28.32 liter

1.0 Introduction

In response to the oil crises of the early 1970s, the federal government dramatically expanded research into renewable energy, with a long-range goal of reducing U.S. dependence on imported oil. Funding levels for renewable energy research and development (R&D) exceeded 1 billion dollars annually (in 1995 dollars) by the late 1970s, but was cut by 80% in 1981. Solar energy R&D funding is rising slowly once again, although it is still at 30% of the 1979-80 levels. This time, the increase in funding is more in response to environmental concerns than to impending gasoline shortages as the oil crisis has been replaced by an oil glut. Solar, wind, biomass, and hydroelectric power are seen as one element in our nation's energy/environmental policy to reduce unhealthy air pollution and to provide an option for reducing greenhouse gas emissions, should that be deemed necessary in the years ahead.

While renewable energy can alleviate many environmental concerns associated with burning fossil fuels, electricity produced by renewable energy does have two limitations: renewable energy is often intermittent, which can restrict its value to small market penetration, and renewable energy in the form of electricity cannot be conveniently used for transportation, one of the major sources of air pollution and the primary consumer of imported oil.

Hydrogen has therefore been proposed as an environmentally friendly alternative energy carrier to supplement electricity. Like electricity, hydrogen creates no pollution in use and can be generated from virtually any energy source. Unlike electricity, however, hydrogen has the potential to overcome the two shortcomings of renewable electricity: hydrogen can be stored for use when the sun isn't shining or the wind isn't blowing, and hydrogen can be used as a convenient transportation fuel. A solar hydrogen system would create virtually no pollution and consume no natural resources during operation. The combination of renewable energy with hydrogen and electricity as energy carriers has the potential to become a long-term, sustainable energy system for our nation and the world.

We do not have to wait for the ultimate solar hydrogen system to begin reaping the benefits of hydrogen as an energy carrier, particularly for transportation systems. Hydrogen produced from existing energy sources, including fossil fuels, could substantially reduce overall pollution from today's vehicles and at costs competitive with gasoline per mile driven.

The Department of Energy (DOE) is currently funding several programs totalling more than $20 million annually to help develop fuel cells for electric vehicles. Fuel-cell electric vehicles (FCEVs) have the potential to increase the energy efficiency of motor vehicles by a factor of up to 2.7—that is, a FCEV would consume 2.7 times less energy than today's gasoline-powered internal combustion engine based on the lower heating value of the fuels. Air pollutants including volatile organic compounds (VOCs) and nitrogen oxides (Nox), the main precursors to urban ozone smog in the summer, and carbon monoxide (CO), the main winter smog ingredient, would be virtually eliminated, even if the hydrogen was derived from natural gas.

To capitalize on the virtues of FCEVs, the nation must also develop a reliable source of hydrogen and the infrastructure to refuel vehicles. Consumers will not purchase and car manufacturers will not build FCEVs if there is no convenient and economic source of hydrogen. DOE is funding two analytical studies to evaluate one approach to developing a hydrogen infrastructure based on steam reforming of natural gas. This approach has great merit, because natural gas is the least expensive transportation fuel, it produces the least carbon dioxide (the main greenhouse gas) per unit of energy output, and the U.S. has ample domestic supplies of natural gas. Steam reforming of natural gas could become the dominant mode of producing hydrogen for the next few decades, generating a robust hydrogen infrastructure that would provide a smooth and seamless transition to solar hydrogen as renewable energy became cost effective in the 21st Century. Hydrogen produced from renewable sources would simply supplement natural gas-derived hydrogen when and where renewable hydrogen became economic, based on the market. As natural gas prices inevitably rise, the cost of hydrogen from wind and biomass may cost less in the Midwest within a decade. Hydrogen from photovoltaics would be less expensive than natural gas in the Southwest somewhat later. Renewable hydrogen would enter the market when and where it could compete economically with hydrogen derived from fossil fuels.

While steam reforming of natural gas may be the intermediate bridge to a renewable hydrogen future, it might have two limitations during the early years of such a transition:

1. Steam reformers may not scale down in size to the smaller units that might be needed initially

2. Natural gas is not available in all parts of the country

The lack of natural gas in some parts of the country could be overcome by trucking liquid hydrogen from large central plants to remote hydrogen gas stations, but small local steam reformers might not be an option.

One alternative to steam reforming of natural gas is to use electricity to electrolyze water. Water and electricity are available virtually anywhere a vehicle might travel, and electrolyzers can be scaled down to very small sizes, including units to supply just one or two vehicles. The purpose of this small ($25K) study contract is to explore the economic viability of water electrolysis as a near-term alternative or complement to steam reforming of natural gas.

Small electrolyzer systems might also be used for initial fleet demonstrations of FCEVs, reducing the large initial capital investment required for steam reformers. Small electrolyzers might even be mounted on trucks or vans that could accompany early FCEV prototype vehicles as they are demonstrated across the country. These mobile, van-mounted hydrogen generators could be plugged into the local electrical grid in each city, thereby generating the hydrogen while the FCEV was being driven around the city. Small electrolyzers might be installed at local residences, giving early FCEV owners the added flexibility of home refueling, and small fleet operators might derive their hydrogen from electrolyzers until such time as the quantities of FCEVs on the road justifies construction of larger natural gas steam reformers.

At first glance, using electricity to produce hydrogen instead of inexpensive natural gas might seem uneconomic. As shown in Figure 1, electricity is the most expensive source of energy for transportation, primarily because two-thirds of the energy is lost at the utility generating station as a result of the Carnot cycle that limits the efficiency of all thermal heat engines. [1] Per unit energy delivered, residential electricity at 8.5 cents/kWh is 3.9 times more expensive than natural gas and 2.6 times more expensive than gasoline, including gasoline taxes. Without road taxes, electricity is 3.7 times more expensive than the cost of retail gasoline at 78 cents/gallon (from $20/barrel oil.).

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[1]Coal-fired steam generators have an efficiency near 33-35%. Newer gas turbines fueled by natural gas can reach 40% efficiency with steam injection or up to 47% efficiency with intercooling. Combined-cycle generators are projected to have efficiencies of 50-55%, which is comparable to fuel cells.

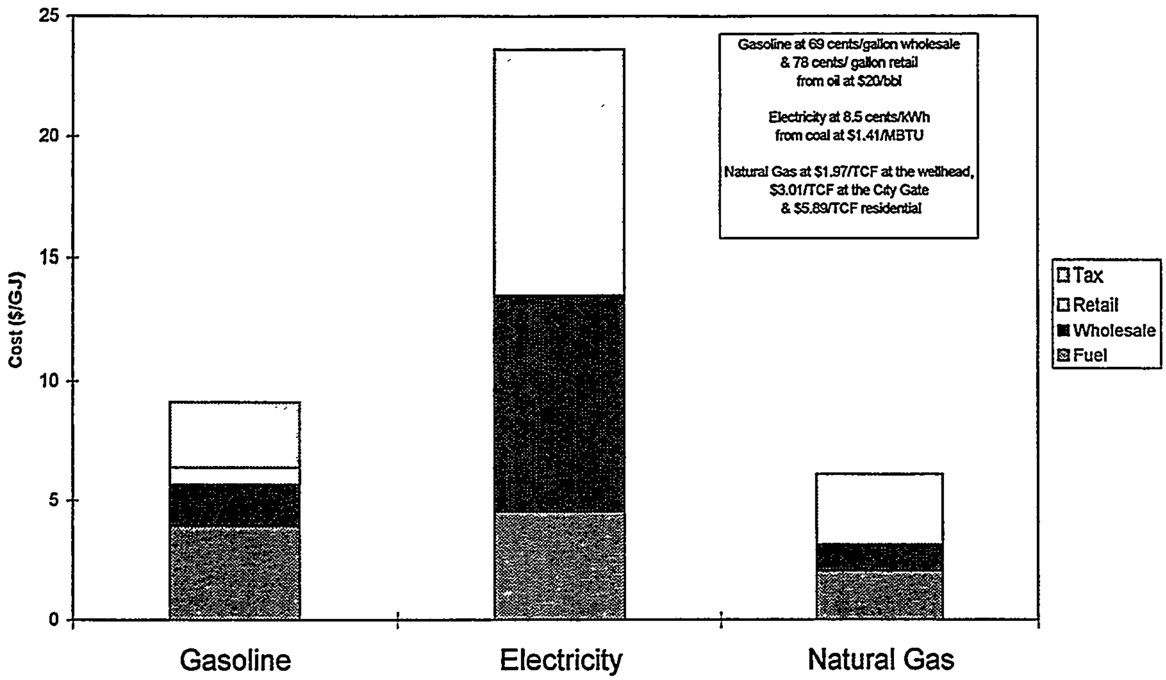

Figure 1. Fuel cost comparison (per unit energy)

However, DTI has estimated that a midsized passenger vehicle powered by fuel cells would have 2.68 times greater energy efficiency (measured as lower heating value, or LHV) on the Federal Urban Driving Schedule (FUDS) than that same vehicle powered with gasoline.[2] On a per-mile basis, then, electricity and natural gas used to produce hydrogen would have a 2.68 factor energy advantage over gasoline, as illustrated in Figure 2. Figure 2 is a plot of the energy feedstock cost per-mile driven, assuming that gasoline fuels an internal combustion engine while electricity and natural gas are used to produce hydrogen for FCEVs.

Figure 2 is based on the average U.S. residential electricity rate of about 8.5 cents/kWh. If off-peak power can be obtained in the range of 2-4 cents/kWh, then electricity would become competitive with natural gas as a feedstock for hydrogen generation, as shown in Figure 3.

The purpose of this study is to explore this potential of using off-peak electricity to produce competitively priced hydrogen. The study focuses on two tasks: an initial conceptual design of small electrolyzer systems, including estimates of their efficiencies and costs, and a brief survey of off-peak electricity rates. The primary output from this analysis is the definition of system costs and electrical rates necessary to make electrolytic hydrogen competitive with gasoline for transportation.[3]

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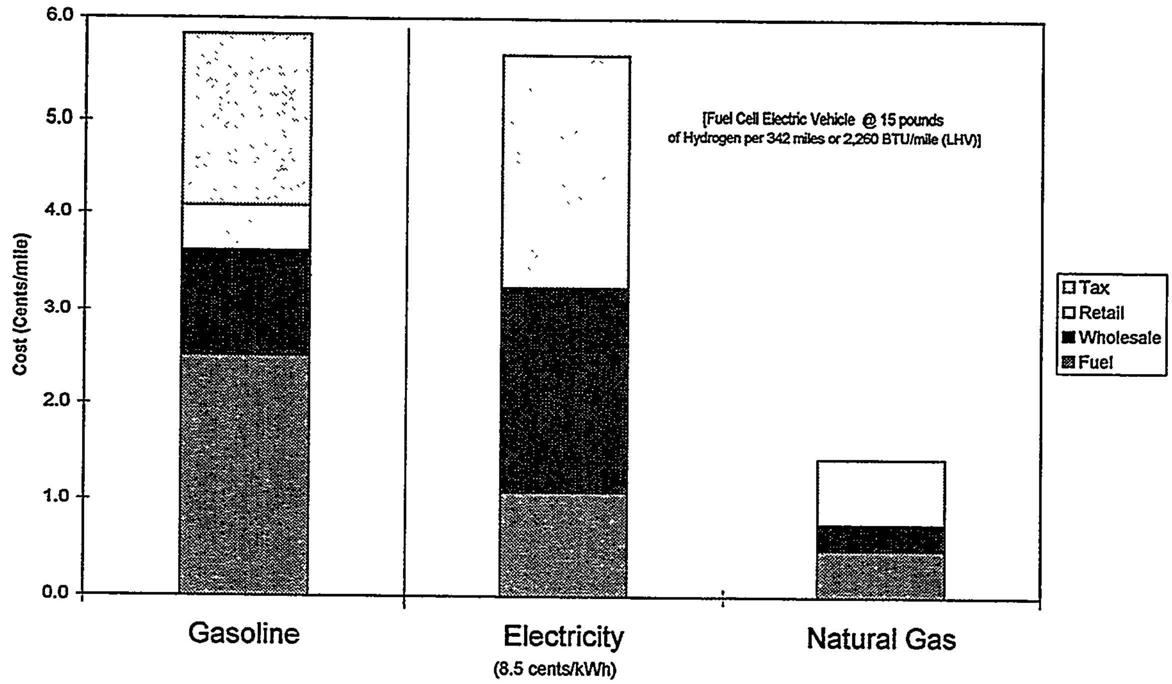
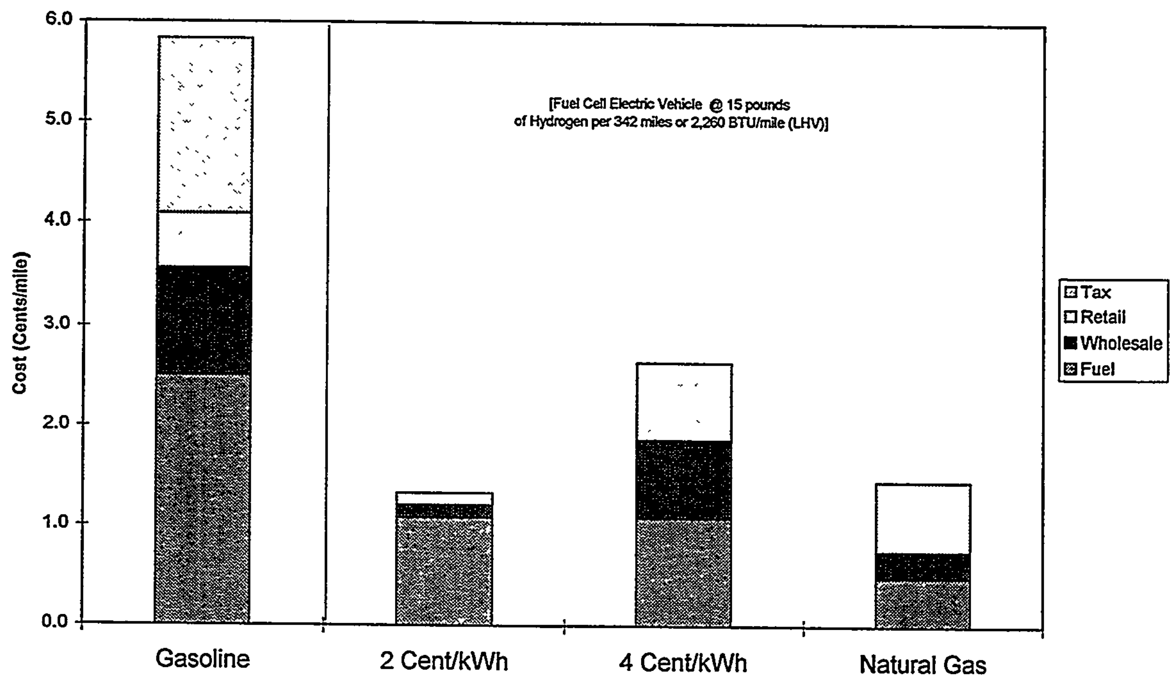
[2]This efficiency gain of 2.68 is based on the LHV of hydrogen and corresponds to the customary use of LHV to rate internal combustion engines. A Taurus-class vehicle with 19 mpg energy efficiency consumes 6,050 BTU/mile (LHV); we estimate that the same vehicle powered by a fuel-cell system would consume 15 pounds of hydrogen to cover the 342-mile FUDS, or 2,260 BTU/mile.

[3]For those drivers who calculate life-cycle costs of owning and operating a vehicle, it may not be necessary for hydrogen costs to be competitive with gasoline. Fuel accounts for less than 10%-15% of life-cycle costs, and the longer lifetime and reduced maintenance expected for fuel-cell vehicles may offset higher hydrogen costs. Nonetheless, we assume conservatively that many drivers will insist on comparable fuel prices at the pump.



Note: Internal Combustion Engine @ 19 mpg=6,050Btu/mile (LHV)

Figure 2. **Fuel costs on a per-mile basis (assuming 2.68 times greater efficiency [LHV] with fuel cell electric vehicle)**



Note: Internal Combustion Engine @ 19 mph = 6,050 Btu/mile (LHV)

Figure 3. **Fuel costs on a per-mile basis (assuming off-peak electricity)**

2.0 Electricity-to-Hydrogen Conversion

2.1 Conceptual Design of an Electrolytic Hydrogen Dispensing System

An electrolytic hydrogen fuel dispensing system would have at least six components, as shown in Figure 4. These are the electrolyzer itself, a compressor, several storage tanks, the dispensing hose and coupling, plus controls and safety equipment. We assume that the unit would be contained in a shed outside the home garage or fleet vehicle facility. Each component is described below.

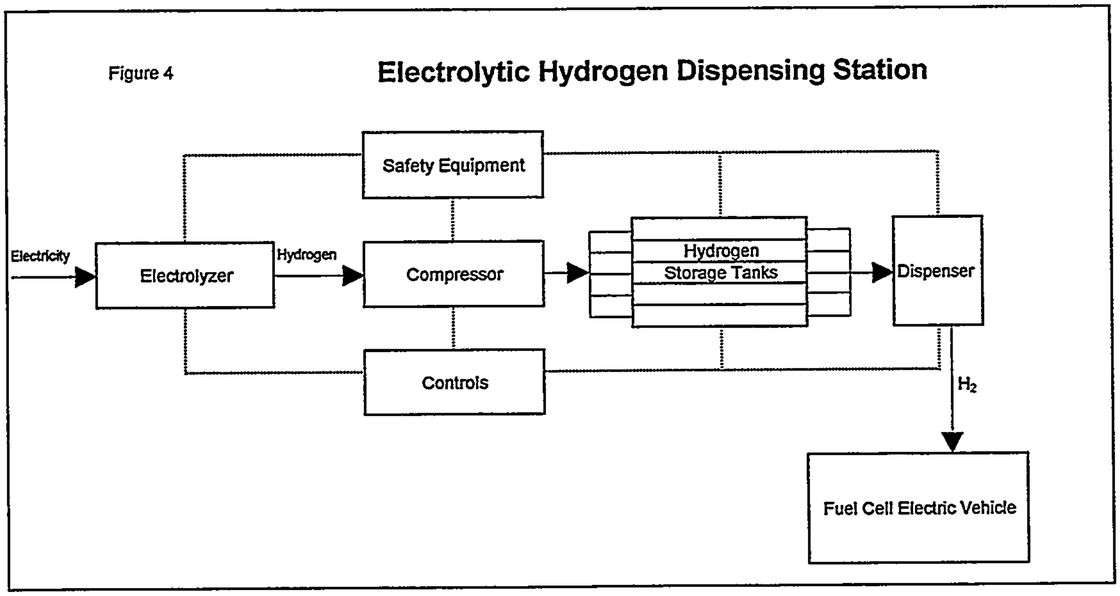


Figure 4. Electrolytic hydrogen dispensing station

2.1.1 Electrolyzer

The electrolyzer must be able to deliver sufficient hydrogen to cover the expected average FCEV consumption, plus enough reserve capacity to handle surge loads. For gas stations handling hundreds of cars per day, this surge capacity need not be large, because the hydrogen delivery rate will be averaged over a large population. If the average load were 200 cars per day, for example, and if the variation about this mean followed a Poisson distribution, then the standard deviation in load would be equal to the square root of the expected value, or 14 vehicles per day in this case. One can design for two standard deviations from the mean, or 228 cars per day, which is just 14% above the average—a surge factor of 1.14. For a 500-car-per-day station, the surge factor need be only 1.09.

In addition to these statistical variations in load, there will be daily, weekend-weekday, seasonal, and other variations. We assume that any refueling system will have enough storage to cover the day/night fluctuations in hydrogen demand. On the average, seasonal gasoline consumption is remarkably uniform across the United States, rising at most by 20% in the summer months compared to winter.[4] These fluctuations will have to be

[4] "Gasoline Consumption by Month, 1992," *National Petroleum News*, June 1994, p. 102.

accommodated by some combination of storage and load following by the electrolyzer system. We assume that any electrolyzer can be operated at rates above its nominal output for short periods of time, possibly at lower efficiency.

For a home refueling system, we cannot rely on statistical smoothing of the load. With only one or two vehicles per refueling station, the peak load on a given day could be many times the average expected load. The average U.S. vehicle travels about 12,000 miles per year. From previous analytical studies of mid-sized passenger cars conducted for DOE[5], DTI has estimated that 15 pounds of hydrogen would be consumed in a FCEV traveling 342 miles on FUDS. This estimate is based on a five-passenger Ford Taurus vehicle with no improvements in drag coefficient, rolling resistance, or weight reductions. Fuel consumption may be reduced for future vehicles, but this estimate is based conservatively on current vehicle technology.

On the average, this Taurus-like FCEV would consume 526 pounds of hydrogen each year, or 1.44 pounds per day. But the electrolyzer must be capable of producing hydrogen at rates above this average to meet seasonal and other variations in driver habits. We have arbitrarily chosen a surge factor of 1.5 for a two-car family. The home electrolyzer must therefore produce at least 4.3 pounds of hydrogen per day.

For a 50-car fleet operator, the electrolyzer would need to provide enough fuel for an average of 18,000 miles per car per year, or 790 pounds per vehicle. The surge factor could be reduced to 1.28, a total electrolyzer capacity requirement of 140 pounds of hydrogen per day.

2.1.2 Compressor

The DTI FCEV design assumes on-board compressed hydrogen storage at 5,000 psi. The refueling station must therefore supply hydrogen at pressures above 5,000 psi, say at 6,000 psi. In theory, the electrolyzer itself could provide the high pressure. The electrochemical loss for operating an electrolyzer at high output pressure is not large. The electrolyzer cell voltage required increases with the logarithm of the pressure ratio:[6]

$$\Delta E = \frac{3RT}{4F} \times \log P_r \qquad (1)$$

where P_r = ratio of output pressure to ambient pressure,
R = gas constant,
T = temperature (°K), and
F = Faraday constant.

This equation predicts a voltage increase of about 36 mv at 100 psi and 25 °C, rising to 94 mv at 2,000 psi and 115 mv at 6,000 psi. In terms of voltage efficiency, an electrolyzer operating with 100 psi output at 1.55 volts might need only 1.63 volts to operate at 6,000 psi output. This would correspond to a voltage efficiency drop from 95.5% to 90.8%. For a proton exchange membrane (PEM) electrolyzer, the back diffusion through the

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[5]Brian D. James, George N. Baum, and Ira F. Kuhn, Jr., *Technology Development Goals for Automotive Fuel Cell Power Systems*, Final Report, Argonne National Laboratory Contract No. 22822402, Directed Technologies, Inc., February 1994.

[6]A.P. Fickett and Fritz R. Kalhammer, "Water Electrolysis," Chapter 1 of *Hydrogen: Its Technology and Implications*, Edited by Kenneth E. Cox and K.D. Williamson, CRC Press, Cleveland, Ohio, 1977, p. 9.

membrane at high pressure would cause some recombination of hydrogen and oxygen, or a current density drop of 4%-8%.[7] The net energy efficiency drop might be from 80% to 70% higher heating value (HHV).

A 6%-10% drop in energy efficiency might justify the elimination of a compressor from the refueling system. However, higher pressure, especially up to 6,000 psi, would probably place other mechanical constraints on the electrolyzer. One manufacturer has designed a PEM electrolyzer that operates with a hydrogen output pressure of 2,000 psi.[8] This design evolved from an electrolyzer that produced oxygen on board a submarine, where the higher hydrogen pressure was required for overboard disposal of hydrogen, which was considered a waste product in this application![9]

If the electrolyzer cannot be built to operate at 6,000 psi, there still may be economic merit in providing high electrolyzer output pressure, say 2,000 psi, to reduce the burden on the compressor. A single-stage compressor could then boost the pressure from 2,000 to 6,000 psi.

The compressor flow rates must match the electrolyzer peak output, which is 4.33 pounds per day in the case of a two-car home refueling system. However, we assume here that the electrolyzer operates only at night to take advantage of off-peak electrical rates. With 12-hour-per-day operation, the hydrogen flow rate from the proposed home electrolyzer would be 0.36 pounds per hour, or 69 SCF/hour.[10]

The theoretical pumping power required is quite small for these flow rates. For an isothermal compression, the pumping power is:

$$P_i = M_f \times R \times T \times \ln\left(\frac{P_o}{P_i}\right). \tag{2}$$

In practice, a compressor will heat the gas, so actual compression is closer to adiabatic compression and the power required would be:

$$P_a = M_f \times R \times T \times \frac{\gamma}{(\gamma-1)} \times \left[\left(\frac{P_o}{P_i}\right)^{\frac{\gamma-1}{\gamma}} - 1\right] \tag{3}$$

[7] Private communication with Jim McElroy of Hamilton Standard, January 6, 1995.

[8] The Hamilton Standard "SPE Hygen-90 Automotive Hydrogen Fuel Generating System" generates up to 12 pounds of hydrogen per day at 2,000 psi.

[9] Private communication with Jim McElroy, December 21, 1994.

[10] We assume here that standard cubic feet (SCF) is defined at 70°F and 1 atmosphere, or a density of 0.00521 pounds per cubic foot, as summarized by the Compressed Gas Association publication CGA G-5-1991, Table 1, p.5.

where M_f = hydrogen mass flow rate (moles per second),
R = gas constant (8.314 J/mol-°K),
T = absolute temperature (°K),
P_i = inlet pressure to compressor,
P_o = outlet pressure, and
γ = the ratio of specific heats (1.42 for hydrogen).

For the home refueling system with a flow rate of 69.2 SCF/hr (0.045 g/sec), the theoretical compressor power required would be 0.23 kW (0.3 hp) for compressing 100 psi to 6,000 psi isothermally, or 0.45 kW (0.6 hp) for 100% efficient adiabatic compression. Assuming a 75% efficient motor/compressor, we would need at most a 0.8 hp motor to compress from 100 psi to 6,000 psi.

If the electrolyzer output pressure was increased to 2,000 psi, then the theoretical compression power required would fall by a factor of 3.7 (isothermal) to 6.1 (adiabatic). A 75% efficient mechanical compressor would then need to supply only 0.1 kW (0.13 hp) to boost the hydrogen from 2,000 to 6,000 psi, assuming adiabatic compression.

This analysis has assumed 5,000 psi on-board hydrogen storage for the FCEV. If low-pressure hydrogen storage such as with metal hydrides proves economically feasible, the costs of the electrolyzer system could be reduced by eliminating the compressor system.

2.1.3 Storage Tanks

The refueling station must store hydrogen both to accommodate intermittent production (assumed to be 12 hours per weekday and 24 hours on weekends) and irregular load profiles. Even with our electrolyzer surge factor of 1.5 for residential units, at least 3 days of storage are required to reach the 12-13 pounds of hydrogen necessary to "top off" a nearly empty FCEV tank with a capacity of 15 pounds. Each car is refueled once every 8-9 days. For the two-car refueling system, we recommend at least two FCEV tanks' worth of usable hydrogen storage, or 30 pounds (5,760 SCF) of hydrogen.

Not all of this hydrogen is usable, however, because some hydrogen will always remain in the storage tanks as the pressure falls during transfer to the vehicle tanks. The hydrogen should be dispersed into at least three separate refueling tanks to provide cascade filling of the vehicle tanks. That is, the vehicle tanks would be filled first from the lowest-pressure storage vessel, moving in succession to the highest-pressure vessel to assure maximum mass flow and minimum compression energy. Even with multiple tanks and cascade filling of the vehicle, at best 60% of the stored hydrogen can be utilized.[11] We have therefore added another factor of 1.6 to the required storage volume to partially offset this inability to transfer a full tank of hydrogen to the vehicle. The system must then store 48 pounds of hydrogen. At 6,000 psi, this amounts to a total tank volume of about 28.6 ft^3 at 70°F.

For the fleet application, the refueling station need not store enough hydrogen to fill all 50 vehicles. Rather, the station need only provide enough storage for one night's production (138 pounds) plus a reserve for unexpected equipment failures or unusual surges in demand (recall that the 138 pound daily production rate already has a surge factor of 1.28 above the average load). A 2-day storage capacity would accommodate a full day's shutdown

[11]Private communication with Tom Halvorson of Praxair, April 11, 1995.

of the electrolyzer for repairs and preventive maintenance. We therefore suggest a storage capacity of 346 pounds of hydrogen. This is equivalent to 6.9 pounds per vehicle in the fleet, compared to 24 pounds of storage capacity per vehicle deemed necessary for the two-car home electrolyzer system.

2.1.4 Dispenser

The refueling system must include the hose and coupling to mate with the vehicle tanks. Presumably, we can take advantage of the natural gas vehicle refueling systems, appropriately modified in terms of flow rate and safety considerations to handle hydrogen instead of natural gas. Quick disconnect couplings would be desirable from the user's perspective, but initial safety considerations might dictate a screw-type coupling.

2.1.5 Control System

The system must include the necessary controls to cycle the electrolyzer and compressor on during the specified off-peak utility hours and turn them off otherwise, plus the sensors and logic to control the sequential filling of the stationary fuel tanks and vehicle tanks, and an automatic shutoff control to respond to various safety sensors. Appropriate meters should be provided to indicate the status of the system, including hydrogen pressures and reserves in the tanks.

2.1.6 Safety System

The refueling system also must include the necessary hydrogen sensors, pressure sensors, and shutoff devices to assure safe operation. We assume that the system will be located outdoors, eliminating the need to provide custom vents in residential garages. To accommodate an inadvertent hydrogen leak, the housing for the refueling station may require special ventilation and possibly catalytic burners to prevent accumulation of hydrogen above the lower flammability limit in air of 4.1%.

The recommended specifications for a conceptual electrolytic hydrogen refueling system are summarized in Table 1.

2.2 Capital Cost Estimates

While a detailed cost analysis of an electrolytic hydrogen refueling station is beyond the scope of this small study contract, we surveyed the literature to estimate the possible capital costs for input to an economic model. This model, in turn, was used to estimate the range of off-peak electrical rates that would be required to make such a refueling station cost competitive with gasoline.

2.2.1 Electrolyzer Capital Cost Estimates

A small number of electrolyzers are sold each year to make hydrogen. Most are exported overseas. While most hydrogen is produced in the United States by steam reforming of natural gas or as a by-product from oil refineries or chemical plants, many developing nations do not have access to large fossil fuel processing plants, cannot afford large steam reforming plants, or do not have access to natural gas. Under these circumstances, many developing nations rely on water electrolysis to provide hydrogen for various scientific or industrial applications. The largest use for electrolytic hydrogen overseas is to cool large electrical generators.[12] Hydroelectric plants

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[12]Private communication with William C. Kincaide and Jay Laskin of Teledyne Brown, during plant tour, December 7, 1994.

Table 1.

Recommended Specifications for a Conceptual Electrolytic Hydrogen Refueling System

		Residential		Fleet	
Number of Vehicles		2		50	
Miles per Year per Vehicle		12,000		18,000	
H_2 Consumption (lb/mile)		0.04386		0.04386	
Surge Factor		1.5		1.28	
Operating Time (h/day)		12		12	
H_2 Production	(lb/day)	4.33		138	
	(SCF/day)	830		26,570	
	(SCF/hour)	69.2		2,214	
	(kW_{out} - LHV)[13]	5.67		174	
Storage Pressure (psi)		6,000		6,000	
Electrolyzer Output Pressure (psi)		100	2000	100	2000
Compressor Power (75% eff. & adiabatic)	(kW)	0.6	0.1	19.2	3.2
	(hp)	0.8	0.13	25.7	4.3
Storage Capacity	(lb of H_2)	48		346	
	(SCF)	9,216		66,400	
	Actual Vol (ft^3)	28.6		200	
Number of Storage Tanks		>3		>5	

[13]The term "kW_{out}" refers to the output LHV of hydrogen, using a heat of combustion of 268.8 BTU/ft^3, Ibid. CGA Table 1.

have very cheap electricity, so installing an electrolyzer system to provide the hydrogen necessary to cool the generators is the most cost-effective option (hydrogen is preferred over air due to its lower wind resistance and higher thermal conductivity). Other uses for electrolytic hydrogen include the semiconductor industry, food processing, and other special applications, such as removing oxygen from argon used for welding.

These electrolyzer systems tend to be large, with one 15-MW plant producing hydrogen at the rate of 7.5 tons of hydrogen per day (LHV and full capacity).[14] But electrolyzer manufacturing volumes are very small, on the order of one or two large systems per year. The main commercial electrolyzer companies (Electrolyser of Canada and Teledyne Brown of Maryland) do make smaller industrial and research laboratory sized electrolyzers, but sales of each product are limited to at most a few dozen per year. The Packard Instrument Company manufactures about 1,000 very small PEM electrolyzers each year, based on the Hamilton Standard technology.[15] These laboratory electrolyzers, used primarily with gas chromatographs, produce about 30 times less hydrogen (1 liter per minute) than would be needed as for a home refueling system. Hence, there is no industrial experience in making thousands or tens of thousands of electrolyzers that might be needed to supply hydrogen for fuel-cell vehicles.

Similarly, the cost studies reported in the literature are primarily limited to very large, single-electrolyzer plants with outputs ranging from 30 to 300 tons of hydrogen per day, whereas the hydrogen refueling systems considered here require only 4.3 pounds (home system) to 138 pounds (50-car fleet) of hydrogen per day. We must therefore extrapolate down by factors of 400 to as much as 140,000 in hydrogen output capacity to provide capital cost data for our model.

The results of our literature sampling are summarized in Table 2. In all cases, the reported cost data have been converted to dollars per kilowatt output of hydrogen, using the LHV of hydrogen ($\$/kW_{out}$ -LHV). Some authors specify the capital costs per unit of input electrical energy to the plant, which neglects the efficiency of the plant. We have used the estimated plant efficiency, if available. Otherwise, we have assumed an electrolyzer efficiency of 67.5% (LHV or 80% HHV). All cost estimates have been converted to 1995 dollars using the gross national product (GNP) implicit price deflator. The studies are summarized below, first for alkaline electrolyzers that are built commercially and then for PEM electrolyzers, which are analogous to PEM fuel cells that use an acid electrolyte embedded in a polymer membrane.

2.2.1.1 Alkaline Electrolyzers

Fluor Daniel, Inc., estimated in 1991 that a 100-megawatt electrical (MW_e) unipolar alkaline electrolyzer with an output of 21,788 m^3/hr would cost $42 million with an efficiency of 60.5% (LHV).[16] The effective capital cost for the electrolyzer would be $\$770/kW_{out}$ in 1995 dollars. The total system cost, including compressors, storage tanks, facility and engineering fees would be about $\$1,600/kW_{out}$.

Electrolyser Corporation of Toronto, Canada, the world's largest producer of commercial electrolyzer systems, recently estimated that the cost of its unipolar alkaline system would be about $400/kW, with a range of $250/kW

[14]Private communication with Andrew Stuart of Electrolyser Corporation, January 31, 1995.

[15]Private communication with Jim McElroy of Hamilton Standard, January 19, 1995.

[16]Pacific Northwest Hydrogen Feasibility Study, prepared for the DOE/Bonneville Power Administration, Portland, Oregon, by Fluor Daniel, Inc., March, 1991.

Table 2.

Electrolyzer Cost Comparison

	Date of Estimate	Cell Type	Efficiency	Plant Size		Cost ($94) ($/kW$_{out}$ - LHV)	
Organization			(HHV)	Input (MW_e)	Output (MW)	Alkaline	PEM
Fluor Daniel	1991	Alkaline	0.716	100	60.5	770	
Electrolyser		Alkaline	(0.80)	100	67	590	
Princeton	1994	Alkaline	0.81	10	6.8	580	
Lawrence Livermore	1994	Alkaline	0.81	2.5	1.7	1275	
Los Alamos	1986	Alkaline	(0.80)	530	360	1350	
Stone & Webster	1984	PEM	0.675	17.5	10		850
Lawrence Livermore	1994	PEM	(0.80)	0.0025	0.00169		1480
General Electric	1977	PEM	(0.80)	50	34		210
Los Alamos	1986	PEM	(0.80)	530	360		410
Hamilton Standard	1994	PEM	(0.80)	0.011	0.00755		330
DTI Projection	1994	PEM	0.80	0.004	0.003		300
DOE/Energetics Projection	1994	Alkaline	0.88	?	?	355	

to \$600/kW.[17] Assuming 67.5% efficiency, this would correspond to about \$592/kW$_{out}$. Officials at Electrolyser are currently evaluating the potential of large-scale manufacture of smaller electrolyzer systems and believe that costs in the range of \$250/kW are feasible.[18]

Dr. Joan Ogden of Princeton University's Center for Energy and Environmental Studies estimated that a 10-MW unipolar electrolyzer would cost about \$371/kW$_e$ at 81% efficiency, or about \$584/kW$_{out}$ in 1995 dollars.[19] Dr. Ogden is currently evaluating in more detail the cost of gas-station-type natural gas steam reformers to provide hydrogen.

Dr. Robert Schock and coworkers at the Lawrence Livermore National Laboratory have been evaluating alternative transportation fuels and have concluded that hydrogen could play a significant role in our nation's energy future. As part of their analysis, they have discussed the cost of both alkaline and PEM electrolyzers with the electrolyzer industry. They have concluded that an electrolyzer system to supply a 300-car-per-day gas station would cost about \$1,275/kW$_{out}$ in small manufacturing quantities, based on a 1.7-MW hydrogen production rate and 68% efficiency (LHV).[20]

In 1986, Blazek et al. estimated that a 100 million standard cubic foot (MSCF) per day hydrogen production plant would cost \$330 million, as reported in a Los Alamos National Laboratory book on hydrogen.[21] This corresponds to an output hydrogen rate of 330 MW$_{out}$ (LHV), or 260 tons per day, which is about \$1,350/kW$_{out}$ in 1995 dollars.

2.2.1.2 Proton Exchange Membrane Electrolyzers

In principle, PEM electrolyzers should be less costly and more user friendly for the home environment than the flowing potassium hydroxide electrolyte characteristic of alkaline electrolyzers. These benefits are offset by the need for potentially expensive catalysts and fragile membranes, analogous to the ongoing debate over the cost of PEM fuel cells. Some have argued that PEM electrolyzers should cost even less than PEM fuel cells, because the electrolysis operation is inherently less complex than the fuel cell process wherein the reactive gases must be introduced over a large area in proper ratios. One electrolyzer manufacturer told us that if General Motors can

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[17] Andrew T.B. Stuart and Matthew J. Fairlie, "Integrated Electrolysis: A Utility Springboard for Sustainable Development," American Institute of Aeronautics and Astronautics, (undated).

[18] Private communications with Matthew J. Fairlie, October 25, November 8, and November 15, 1994.

[19] Joan M. Ogden and Mark A. DeLuchi, "Renewable Hydrogen Transportation Fuels," The 9th World Hydrogen Energy Conference, March 13, 1992 draft for June 1992 conference.

[20] G. Berry, P. Campos, G. Rambach, and R. Smith, "Integrated Economic and Technical Assessments of Hydrogen Transport and Storage," presented at the DOE Hydrogen Program System Studies Meeting, July 19, 1994.

[21] C.F. Blazek, E.J. Daniels, T.D. Donakowski, and M. Novil, "Economics of Hydrogen in the '80's and Beyond," K.D. Williamson, Jr. and Frederick J. Edeskuty, editors, Chapter 1 in *Recent Developments in Hydrogen Technology, Vol. II* CRS Press, 1986.

make PEM fuel cells for $34/kW$_p$ in very large manufacturing volumes[22], then they should, in principle, be able to make PEM electrolyzers for even less.[23]

However, we do need to distinguish between the costs of stationary and mobile fuel cells when we make analogies to electrolyzer costs. Electrolyzers should be compared with stationary fuel cells, not mobile fuel cells, because three factors tend to make fuel cells for transportation less expensive than stationary fuel cells used for nearly continuous power production. First, fuel cells designed for motor vehicles need operating lifetimes on the order of 5,000 hours (100,000 miles), whereas stationary fuel cells should be built to last at least 50,000 hours (5 years life). Second, fuel cells for transportation tend to have much higher peak current densities, on the order of 1,000 amps per square foot (ASF), compared to 200 ASF for stationary fuel cells. Vehicle fuel cells need the high peak power for sustained high-speed hill climbing, although the average power load is much less. Because much of the fuel cell cost scales with cell area, and hence inversely with current density, mobile fuel cells tend to be less costly on a per-peak-watt basis. Finally, mobile fuel cells will be manufactured in very large quantities, possibly millions per year, whereas stationary fuel cells may never achieve these high production levels.

All three factors (lifetime, current density, and manufacturing volume) tend to make fuel cells for transportation less costly per peak watt than stationary fuel cells. Thus, it is consistent to estimate a cost of $34/kW for a vehicle fuel cell in very high manufacturing volumes while at the same time predicting a cost of $300/kW for stationary fuel cells—the DOE goal—in somewhat lower manufacturing volumes. The appropriate comparison for electrolyzers is $300/kW; if we can build stationary fuel cells for $300/kW, then industry should be able to build electrolyzers for less than $300/kW.

Returning to our literature survey, the General Electric Company (GE) analyzed the merits of the PEM electrolyzer in 1977, and estimated a cost of $77/kW$_{out}$ (HHV) from a 50-MW$_e$ plant.[24] Correcting for LHV and inflation, this would correspond to about $210/kW$_{out}$ (LHV) in 1995 dollars.

Stone & Webster estimated in 1984 that a 10-MW$_{out}$ (HHV) PEM electrolyzer plant producing 2.55 MSCF of hydrogen per day would cost between $4 and $6 million, with an efficiency of 57% (LHV).[25] Taking the average estimate of $5 million and correcting for inflation, this amounts to about $850/kW$_{out}$ (LHV).

The Los Alamos book also included an estimate for the GE PEM electrolyzer technology, estimating $305/kW$_{out}$ in 1986, or $410/kW$_{out}$ in 1995 dollars.

More recently, the PEM technology has been acquired by Hamilton Standard, a division of United Technologies Corporation, which also owns International Fuel Cells. Hamilton Standard has designed a PEM home electrolyzer system that they call the SPE HYGEN-90.[26] This unit is designed to produce up to 12 pounds of hydrogen per

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[22] *Research and Development of Proton-Exchange Membrane (PEM) Fuel Cell System for Transportation Applications: Initial Conceptual Design Report*, Prepared for the Office of Transportation Technologies, U.S. Department of Energy by Allison Gas Turbine Division of General Motors, EDR 16194, November 30, 1993, p. C-4. (The GM/Allison price estimate is often quoted as $46/kW, but this estimate includes a methanol reformer. The actual fuel cell system estimate is $34/kW without the reformer.)

[23] Private communication, William Kincaide and Jay Laskin of Teledyne Brown, December 7, 1994.

[24] Ibid., Fickett & Kalhammer, p. 38.

[25] T.J. Soychak, Stone & Webster Engineering Corporation proposal for the Washington Water Power Company, June 1984.

[26] "SPE" is a registered trademark of Hamilton Standard.

day at pressures up to 2,000 psi. The Carrier Division of United Technologies, which manufactures home air conditioners in large volumes, has estimated the price of this unit at $5,000 in quantities of 100,000. However, this estimate includes a markup of 100%, and the Carrier engineers believe that they could reduce the actual manufacturing cost to less than $2,500 each.[27] Twelve pounds per day translates into 7.55 kW_{out} (LHV), or a cost of $330/$kW_{out}$, again based on manufacturing 100,000 electrolyzer systems each year. This is the closest approximation to the type of system we are considering in this study. We have therefore selected $300/$kW_{out}$ as our projection for possible home electrolyzer capital costs for our computer economic model.

The Lawrence Livermore National Lab also estimated the cost of a home electrolyzer based on discussions with industry. They used a value of $3,500/$kW_{out}$ for one presentation[28], but subsequently clarified that this estimate was intended as a full home electrolyzer system, possibly including a compressor and storage system, in very low production runs. Livermore has since estimated that a 2.5-KW input electrolyzer should cost about $1,000/$kW_{in}$[29], which corresponds to $1,480/$kW_{out}$ (LHV) assuming 67.5% electrolyzer efficiency (LHV).

This $1480/$kW_{out}$ estimate is for the first few units built and does not include a manufacturing learning curve. Figure 5 shows the historical cost reductions for common electronic consumer devices in large manufacturing volumes. Color televisions had an average reduction in manufacturing costs of 94% for each doubling of production, while black and white televisions fell 90% and radios fell 83.2% for each doubling of production.[30] If we assume that the Livermore estimate is based on producing just ten electrolyzers for $1,480/$kW_{out}$, then the Hamilton Standard estimate of $330/$kW_{out}$ for 100,000 units falls very close to the 90% learning curve on Figure 5 for black and white televisions.

The results of this electrolyzer cost survey are plotted in Figure 6 as a function of plant output, which illustrates the wide (logarithmic) gap between the bulk of the data estimates for plants producing more than 1 MW of hydrogen (1,600 pounds/day) and the home electrolyzer at 4 pounds per day. We also show our estimate ("+" symbol) of possible home electrolyzer cost at $300/$kW_{out}$ based on very large production runs. For comparison, DOE's Hydrogen Program Office is collecting a database of cost and efficiency estimates for various hydrogen energy components. The current cost projections for electrolyzers from this database are summarized in Table 3.

These data are costs divided by input energy, and presumably refer to large-scale electrolysis plants and very low manufacturing volumes characteristic of the literature (no size is specified). The $300/$kW_e$ estimate at 90% (HHV) corresponds to about $395/$kW_{out}$ (LHV), which is low for large-scale alkaline electrolyzers described in the literature but representative of the values we believe may be possible through high-volume production. It is unclear why the DOE projections are so high for PEM electrolyzers.

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[27] Private communication with Jim McElroy of Hamilton Standard, December 21, 1994.

[28] Ibid, Gene Berry.

[29] Private communication with Ray Smith, January 13, 1994, and memorandum from Gene Berry to Ray Smith dated 21 December, 1994.

[30] Y.E. Yelle, "The Learning Curve: Historical Review and Comprehensive Survey," Decision Sciences, Vol. 10, pp. 302-328, April 1979.

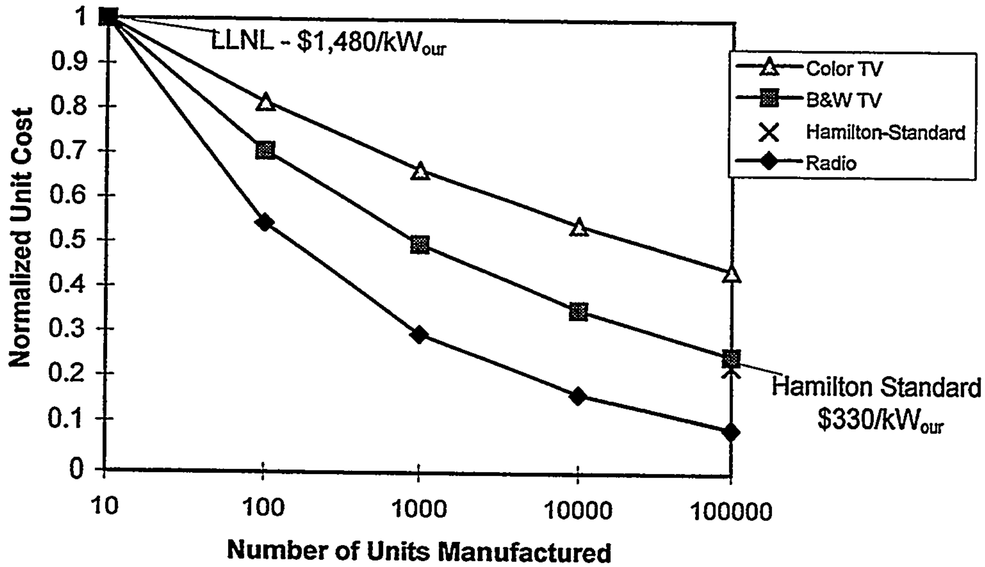

Figure 5. Cost reduction with manufacturing volume

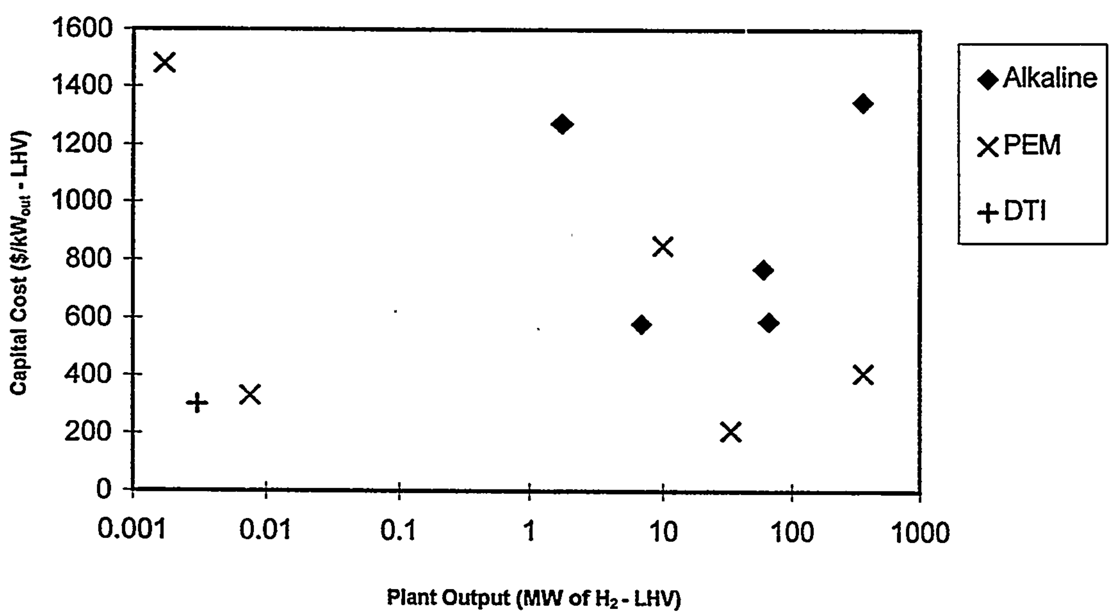

Figure 6. Electrolyzer capitial cost estimates

Table 3.

DOE Projections of Electrolyzer Capital Costs and Efficiencies[31]

	Current Cost	2000-2005	2020+
Alkaline Electrolyzer	\$500/kW[32] 80% (HHV)	\$350/kW 88%	\$300/kW 90%
PEM Electrolyzer	\$2,400/kW 87%	\$2,000/kW 90%	\$1,700/kW 94%
Steam Electrolysis	\$415/kW 75%[33]	\$350/kW 77%	\$300/kW 78%

Before leaving electrolyzer capital cost estimates, it is worth noting that capital costs for steam reformers have been estimated to rise rapidly with decreasing hydrogen output, as shown in Table 4 and Figure 7. In the larger sizes (above 10 MW or 8 tons per day), steam reformers and electrolyzers seem to be competitive on a capital cost basis, meaning that hydrogen from reformers should be less costly now due to the low cost of natural gas. Below 5 MW (4 tons per day), steam reformers may become more costly than electrolyzers due to diseconomies of scale. Because hydrogen gas stations will require one half to 3 tons per day production, this area needs to be explored in much more detail.

2.2.2 Compressor Capital Cost Estimates

Dr. Joan Ogden et al. have estimated the cost of a 300-car per day hydrogen gas station using steam reforming of natural gas.[34] Their analysis included the cost of a compressor for boosting the hydrogen from 200 psi to 8,400 psi. The compressor cost \$190,000 and delivered 1.2 MW of hydrogen (LHV), a cost of $\$158/kW_{out}$.

As with electrolyzers, however, this cost is based on low-volume manufacturing. For many home electrolyzers, the emerging natural gas refueling industry may provide a better estimate for our purpose. For example, FuelMaker of Toronto, Canada is marketing a small compressor for home refueling of natural gas vehicles. This unit delivers 1.7 SCFM of natural gas at pressures up to 3,000 psi. We need twice the pressure but 70% of this flow rate.

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[31] J. Philip DiPietro and Joseph S. Badin, *Technology Characteristics for the E3 (Energy, Economics, Environment) Pathway Analysis*, draft, July 1994.

[32] The range of cost estimates from the literature, according to the Energetics data base, is from \$270/kW to \$1,200/kW.

[33] The Steam Electrolyzer efficiency calculation includes the energetic cost of the steam. The electrical efficiency is slightly more than 100%, excluding the cost of steam input energy.

[34] Joan M. Ogden, E. Dennis, and John W. Strohbehn, "A Technical and Economic Assessment of the Role of Natural Gas in a Transition to Hydrogen Transportation Fuel," presented to the 10th World Hydrogen Energy Conference, Cocoa Beach, Florida, June 20-24, 1994.

Table 4.

Natural Gas Steam Reformer Capital Cost Estimates

		Output		Cost ($94)
Organization	Date of Estimate	MW (LHV)	Tons/Day	($/kW$_{out}$ - LHV)
Los Alamos	1985	0.328	0.26	3570
Princeton	1994	1.20	0.96	1850
Lawrence Livermore	1994	1.38	1.10	1560
Los Alamos	1984	1.57	1.26	1300
Ogden & Nitsch	1989	1.71	1.37	1260
Los Alamos	1983	7.87	6.30	518
Los Alamos	1982	328	262	333
Hord & Parrish	1975	600	480	93

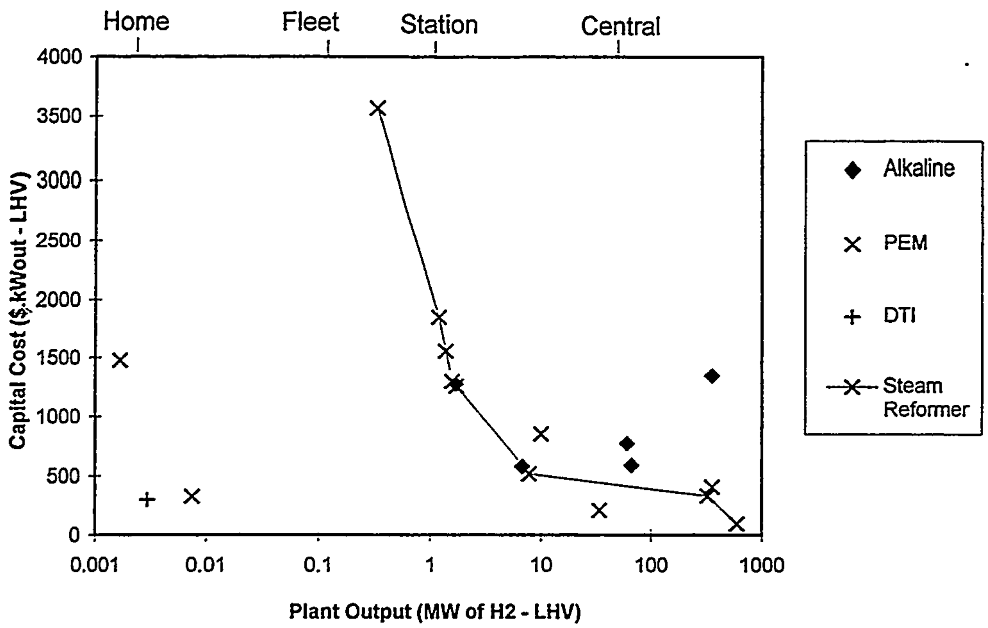


Figure 7. Capital cost estimates for steam reformers and electrolyzers

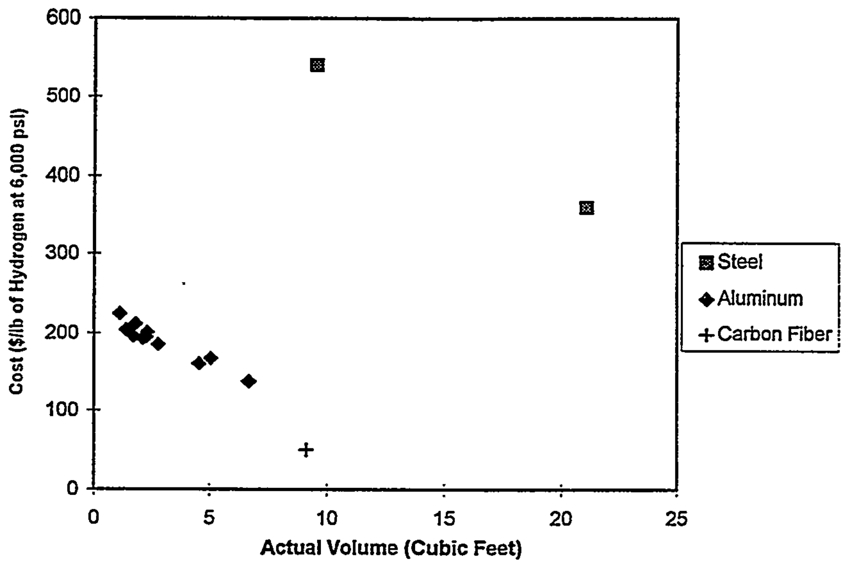
The FuelMaker is selling for $4,000 now; the manufacturer estimates that the price could be cut to $2,000 in quantities of 10,000 and to $1,120 in quantities of 100,000.[35] This corresponds to about $115/kW$_{out}$, which we use in our economic analysis for compressor cost.

2.2.3 *Storage Tank Capital Cost*

High-pressure storage vessels are generally custom made, so commercial prices are not indicative of high-volume manufacturing rates. Tank cost estimates are shown in Figure 8 for 6,000 psi steel tanks and for 3,600 psi composite, fiber-reinforced aluminum tanks in small quantities.

The DTI datum point is our estimate for a 9-cubic-foot tank made from carbon filament composites, based on large-scale production of tanks for a hydrogen vehicle. Clearly, the stationary tank does not need to be made out of very expensive carbon fibers when weight is of no concern and less expensive steel or aluminum tanks will suffice. But because we were not able to find an estimate for high-volume manufacturing of aluminum or steel tanks, we use the high-volume manufacturing carbon price estimate of $60 per pound of stored hydrogen for the economic analysis.

[35] Private communication with Matthew Fairlie of Electrolyser Corporation, December 5, 1994.



Steel Quote from CP Industries, Inc of McKeesport, Pennsylvania
For 6,000 psi ASME steel tanks, 16" OD x 1.416" wall.

Aluminum Quote from NGV Systems, Inc of Long Beach, California
For 3,600 psi composite reinforced aluminum cylinders

Carbon Fiber tank is DTI projection for 2004, based on 6,000 psi carbon fiber wrapped plastic tanks with metalized liner.

Figure 8. Stationary storage tank costs

2.3 Economic Model

To determine the range of acceptable off-peak electrical rates to make electrolytic hydrogen cost competitive with gasoline, we wrote a simple economic computer model. This model calculates the life-cycle costs of electrolytic hydrogen ($/lb) as a function of the cost of electricity. The total annual expenses are assumed to be:

$$E = (CRF + o + i + t_p) \times C + C_e \qquad (4)$$

where CRF is the annual capital recovery factor:

$$CRF = \frac{d}{1 - \left(\frac{1}{1+d}\right)^N} \qquad (5)$$

o = operating and maintenance costs (% of capital)
i = annual insurance (% of capital),
t_p = annual property taxes (% of capital),
d = discount rate,
N = the lifetime of the component in year (or economic recovery period),
C = total installed capital cost of electrolyzer, compressor, tanks and associated controls, and
C_e = annual cost of electricity to run both the electrolyzer and the compressor.

We calculated the hydrogen cost under three different financing scenarios: a business with a 10% expected rate of return over 15 years (after taxes and after correcting for inflation); a utility with a 9% discount rate (6.3% corrected for inflation) and 15-year lifetime; and a home with the electrolyzer system included in a 30-year, 9% mortgage.

For the home mortgage case, we assumed that the home owner would deduct interest payments from both state and federal income tax, so the effective discount rate becomes:

$$d = i_m \times [1 - T_f - T_s \times (1 - T_f)] \tag{6}$$

where i_m = mortgage interest rate (9%)
T_f = federal marginal income tax rate (31% for couple with \$89K to \$140K income), and
T_s = state income tax rate (5.75%).

For the business case, we assume that the company demands an after-tax real rate of return of 10%. The company would make the investment in an electrolyzer system only if the rate of return is equal to that of other possible investments. The company would set the discounted cash flow rate of return such that the net present value of the project is equal to zero. The price of hydrogen must be set so that the net annual revenues minus the net annual expenses yields zero present worth for the investment. The hydrogen production plant would then produce the same constant-dollar, after-tax return (10%) as any other investment with a real 10% return.

To account for inflation, the discount rate for the business becomes:

$$d = r + i + i \times r \tag{7}$$

where r = after-tax real rate of return on the investment in constant dollars, and
i = general inflation rate.

To account for corporate income tax, we must choose a depreciation schedule. The IRS currently specifies the Modified Accelerated Cost Recovery System (MACRS), which allows somewhat accelerated depreciation for the first 5 years of a 15-year recovery period. But MACRS also delays the first-year depreciation by 6 months, which almost offsets the value of the accelerated recovery schedule from a net present value perspective. As a result, straight-line depreciation is a sufficiently accurate surrogate for MACRS on a zero- present-worth basis.

Including depreciation and federal income tax (property taxes are included in fixed expenses), the total business expenses are:

$$E_b = \left[\frac{\left(CRF - \frac{T_b}{n}\right)}{(1 - T_b)} + o + i + t_p\right] \times C + C_e \tag{8}$$

where T_b = the corporate income tax rate.

The resulting cost of hydrogen per pound is shown in Figure 9 as a function of the price of electricity for the three different financing arrangements. For comparison, we have also plotted the effective retail cost of gasoline converted to \$/lb of hydrogen, assuming 19 mpg for the internal combustion engine vehicle and crude oil selling at \$20/barrel. (For reference, the cost of oil to refiners over the last two decades is summarized in Figure 10.) The retail cost of gasoline (\$/gal) to large users was estimated by a linear regression analysis of the average U.S. gasoline retail price versus the price of crude oil (at the refinery) from 1978 through 1993:[36]

$$P_R = 2.41 \times P_c + 29.36 \tag{9}$$

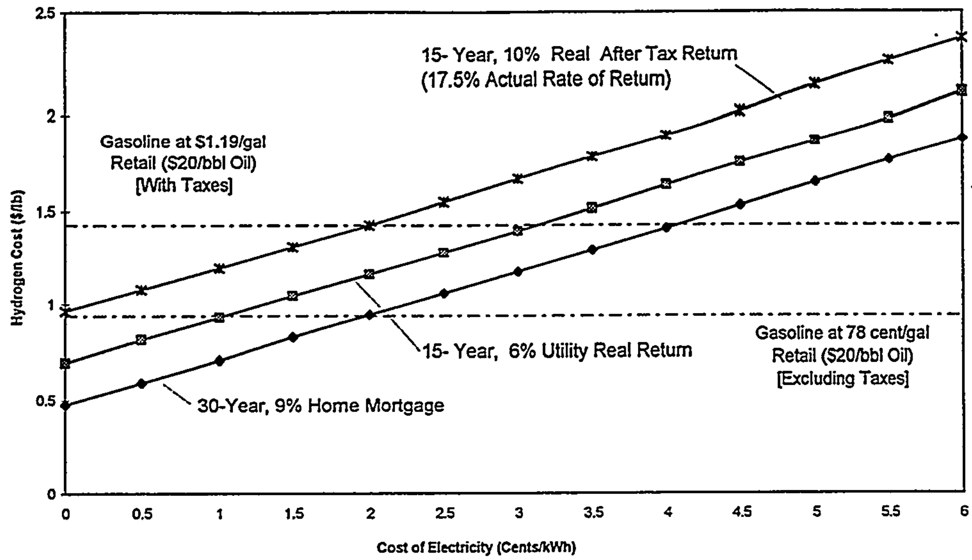
where P_c is the refinery cost of crude oil (\$/barrel). At \$20/barrel, the average retail cost of gasoline is 78¢/gallon.

To convert this gasoline in \$/gal to effective hydrogen cost in \$/lb, recall our estimate that a Taurus-like FCEV requires 15 pounds of hydrogen to travel 342 miles on the FUDS cycle, while the internal combustion engine with 19 mpg efficiency requires 342/19 = 18 gallons of gasoline to cover the same distance. The conversion factor is therefore 18/15 = 1.2 gallons of gasoline per pound of hydrogen. Thus, the 78 cents/gallon of gasoline is equivalent to 93.6 cents/pound of hydrogen, plotted as the lower horizontal line in Figure 9.

We have also plotted the retail price of gasoline, including federal, state, and local excise taxes,[37] on Figure 9. Normally this comparison would not be valid, because any motor fuel would eventually be taxed at the same rate as gasoline to raise money for highway construction. By this reasoning, we should compare only wholesale costs of alternative fuels without taxes. But, in this case, the home owner would have a choice between paying for retail gasoline with taxes or using electricity to produce hydrogen at home. Initially, there would be no tax on this source of fuel.

[36] Monthly Energy Review, Energy Information Administration, DOE/EIA-035(94/03), March, 1994. The crude oil price is the composite refiner acquisition cost listed in Table 9.1, "Crude Oil Price Summary," p. 109. The retail gasoline price was taken from Table 9.7, "Refiner Prices of Petroleum Products to End Users," p. 115, for the years 1978 through 1993.

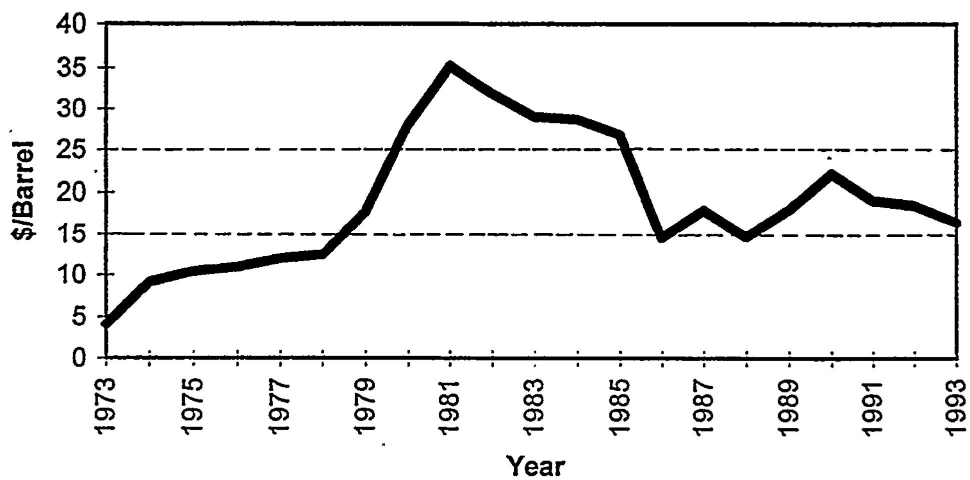
[37] The federal excise tax on gasoline is currently 18.4 cents/gallon, while the average state road tax on gasoline is about 22.9 cents/gallon, varying from a low of 8 cents in Alaska to a high of 28 cents in Connecticut. We have added 41 cents/gallon as an average of all gasoline taxes.



		Home	Utility	Business
Capital Cost				
Electrolyzer	$/kW out	300	300	300
H2 Storage	$/lb	60	60	60
Compressor (6 kpsi)	$/kW out	115	115	115
Total Capital Cost	$	$4,493	$4,493	$4,493
Hydrogen for 342 mile	lbs	15	15	15
Number of Vehicles		2	2	2
Miles/year/vehicle	miles	12,000	12,000	12,000
Storage capacity	[# of tanks/vehc.	1.6	1.6	1.6
H2 Production X Ave		1.5	1.5	1.5
Days to Produce One Tank:		3.5	3.5	3.5
ICE Mileage	mpg	19		
Cost of Crude Oil	$/barrel	20		

		Home	Utility	Business
Lifetime	Years	30	15	15
Discount Rate	% / 100	0.0585	0.089	0.1297
CRF	[calc]	0.0715	0.1230	0.1854
Capacity Factor	Ratio	0.7	0.7	0.7
Electrolyzer Efficiency	LHV%/100	0.675	0.675	0.675
Compressor Electr.	kWh/kWh H	0.065	0.065	0.065
O&M	% of Capital	0.02	0.02	0.02
Insurance	% of Capital	0.005	0.005	0.005
Property Taxes	% of Capital	0.015	0.015	0.015
Real Interest Rate	%/100	0.09	0.06	0.1
Fed. Marg. Inc. Tax	%/100	0.31	0	0.26
State Income Tax	%/100	0.058		

Figure 9. Cost of eletrolytic hydrogen



Source: Directed Technologies, Inc.

Figure 10. Cost of oil to refiner

There is precedent for hydrogen not being taxed as heavily as gasoline or not being taxed at all, at least initially. For example, natural gas vehicles currently are taxed at a lower rate than gasoline at the federal level, and some states have reduced their highway taxes for natural gas to encourage the use of this cleaner burning fuel, as indicated in Table 5.

More importantly, electric vehicles at this time have no highway tax burden at either the federal or state level—no state levies or excise tax on electricity used to charge electric vehicles. This may change as electric vehicles become more plentiful and as tax revenues for highway funds decrease. But governments also may decide to shift more of the tax burden to the more polluting fuels through "carbon taxes" to encourage the use of clean fuels such as hydrogen. In any case, we do not anticipate any highway taxes initially for electrolytic hydrogen, if for no other reason than that collecting them would be complex, particularly with mobile hydrogen refueling vans roaming the countryside and home owners plugging electrolyzers into their home electrical outlets. Therefore, we consider the fully taxed retail gasoline price to be an appropriate benchmark to compare with early hydrogen production costs.

Returning to Figure 9, electrolytic hydrogen is cost-competitive with fully taxed gasoline as long as electricity costs less than 2-4 cents/kWh, depending on the economic assumptions. If hydrogen-powered FCEVs take over a large market share and if governments begin to tax hydrogen at the same rate as gasoline, then electricity prices would have to be less than 2 cents/kWh for electrolytic hydrogen to remain competitive with gasoline. By that time, however, the reduced operating and maintenance costs and the longer lifetime of FCEVs may more than offset any increased cost of fuel taxes.

The cost components in the electrolytic hydrogen price are shown in Figure 11 for each economic case, assuming electricity at 2.5 cents/kWh. For the utility-type 15-year loan, electricity accounts for about half of the estimated

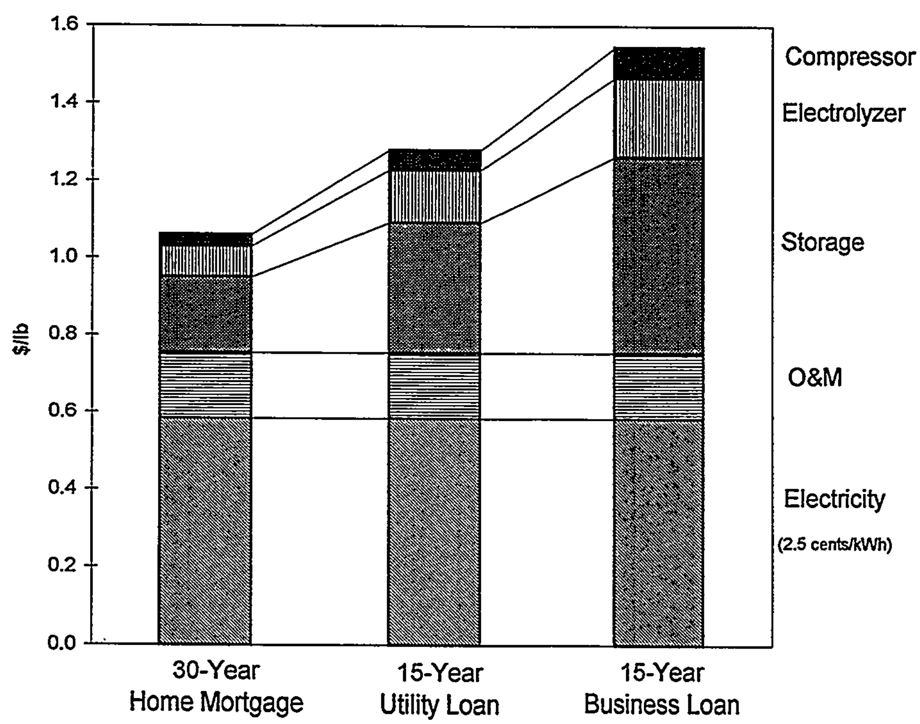


Figure 11. Electrolytic hydrogen production cost

Table 5.

Motor Fuel Tax Rates as of January 1993[38]

(Cents/gallon)

	Gasoline	Natural Gas	Electricity
Federal	18.4	5.9	0
Alabama	18	17	0
Arizona	18	1	0
Arkansas	18.7	0	0
California	17	7	0
Colorado	22	20.5	0
Iowa	20	16	0
Kansas	18	17	0
Kentucky	15.4	12	0
Maryland	23.5	21.75	0
Montana	21.4	7.49	0
Nevada	24	20.5	0
New Jersey	10.5	5.25	0
New Mexico	17	16	0
New York	22.89	8	0
Oklahoma	17	16	0
Oregon	24	22	0
Pennsylvania	22.4	12	0
Tennessee	20	13	0
Virginia	17.5	16	0
Wyoming	9	0	0

[38] Source: the Natural Gas Vehicle Association, Arlington, Virginia. Only states with lower tax on natural gas than on gasoline are shown.

cost. Surprisingly, storage accounts for more than the cost of the electrolyzer and compressor combined. Operation and maintenance (which includes taxes and insurance on this chart) is almost as expensive as the electrolyzer capital cost recovery. Figure 12 shows the cost components for the home mortgage case as electricity price is varied.

All previous charts have assumed a home electrolyzer supplying two FCEVs. Figure 13 illustrates the reduction in cost for a 50-car-fleet dispensing station and a 160-car-per-day gas station. The larger dispensing sites could afford electricity at about 2 cents/kWh higher (5 vs. 3 cents/kWh) than the home electrolyzer and still remain competitive with fully taxed gasoline. These cost reductions are due strictly to the reduced surge capacity required for hydrogen production and the reduced storage capacity as a result of more vehicles being serviced by the larger dispensing sites. We have assumed here that the capital cost per unit hydrogen output for the electrolyzer, compressor, and storage system would be identical for the home electrolyzer, the fleet operation, and the larger gas station. If the electrolyzer component costs are less for larger units, then the larger dispensing stations could afford even higher cost electricity and still be competitive with gasoline.

We conclude that off-peak electricity that costs as much as 4-4.5 cents/kWh could produce competitively priced hydrogen for early fleet applications.

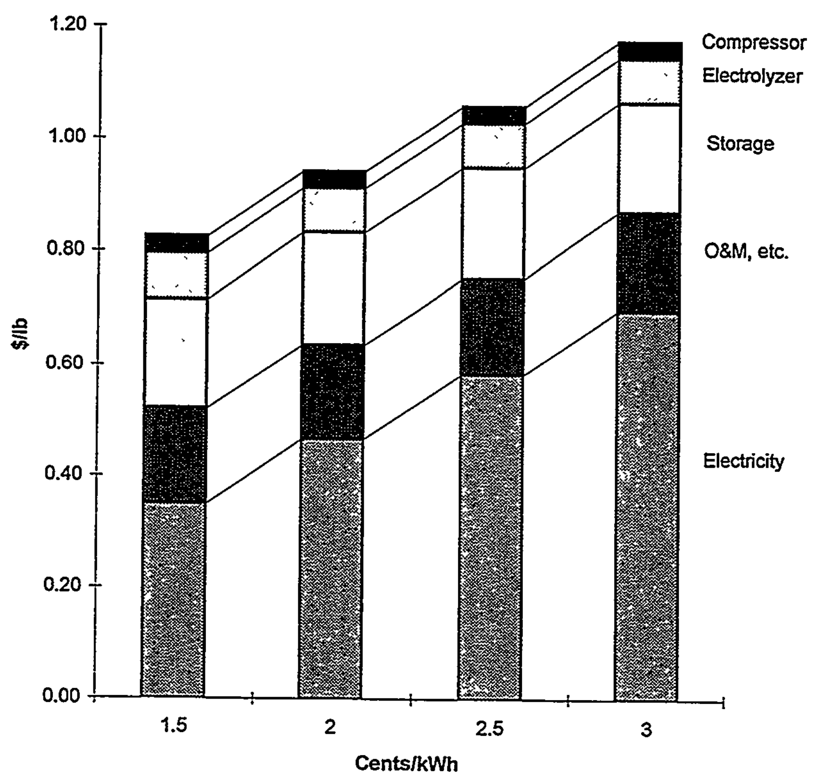
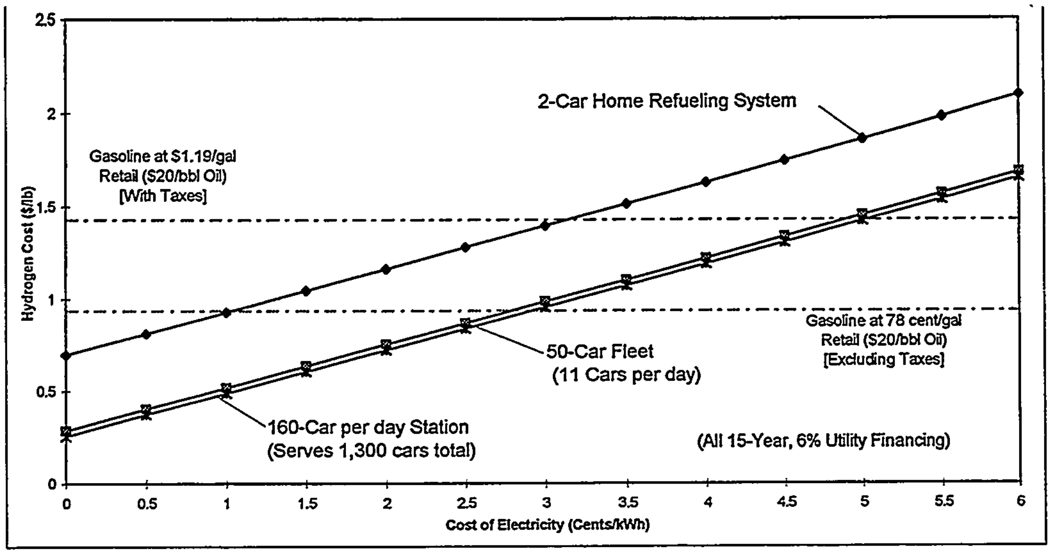


Figure 12. Electrolytic hydrogen production cost



		Home	Fleet	Station
Capital Cost				
Electrolyzer	$/kW out	300	300	300
H2 Storage	$/lb	60	60	60
Compressor (8kpsi)	$/kW out	115	115	115
Total Capital Cost	$	$4,493	$69,173	$1,072,945
Hydrogen for 342 mile	lbs	15	15	15
Number of Vehicles		2	50	1300
Miles/year/vehicle	miles	12,000	18,000	12,000
Storage capacity	[# of tanks/vehc.	1.6	0.462	0.26
H2 Production X Ave		1.5	1.2	1.1
Days to Produce One Tank:		3.5	0.1	0.0

		Home	Fleet	Station
Lifetime	Years	15	15	15
Discount Rate	% / 100	0.0600	0.06	0.06
Real Discount Rate	% / 100	0.0886	0.089	0.08862
CRF	[calc]	0.1230	0.1230	0.1230
Capacity Factor	Ratio	0.7	0.7	0.7
Electrolyzer Efficiency	HHV%/100	0.675	0.675	0.675
Compressor Electr.	kWh/kWh H	0.065	0.065	0.065
O&M	% of Capital	0.02	0.02	0.02
Insurance	% of Capital	0.005	0.005	0.005
Property Taxes	% of Capital	0.015	0.015	0.015
Interest Rate	%/100	0.06	0.06	0.06
Fed. Marg. Inc. Tax	%/100	0.31	0	0
State Income Tax	%/100	0.0575		
Inflation Rate	%/100	0.027	0.027	0.027

Figure 13. Cost of electrolytic hydrogen as a function of refueling station size

3.0 Low-Cost Electricity Availability

One objective of this study was to evaluate the availability of low-cost electricity to produce hydrogen, with emphasis on hydroelectric and other renewable energy. We will consider renewable energy first, followed by an analysis of existing off-peak electricity and the marginal costs of producing electricity today using the current mix of generating units.

3.1 Renewable Electricity

Hydroelectric plants supply about 9.9% of U.S. electricity today, third in line behind coal and nuclear energy, as shown in Figure 14. Hydroelectricity is normally quite inexpensive for existing plants. Two utilities that rely on hydroelectricity for 99% of their generating capacity, Idaho Power Company and Washington Water Power Company, offer residential customers rates of 4.83 and 4.9 cents/kWh, respectively, well below the U.S. average residential revenue of 8.8 cents/kWh.[39] But hydroelectricity is not always inexpensive. The average residential revenue for the Bangor Hydro Electric Company, which is 100% hydroelectric, is 12.47 cents/kWh, well above the national average.

One might expect that cheap hydroelectricity could be used at night to produce hydrogen for use in FCEVs, at least in certain parts of the country. However, hydroelectricity, unlike solar or wind energy, often can be stored behind dams, increasing its value during the afternoon peak load hours. Utilities have no reason to sell their electricity at bargain basement rates at night if they can store it until it commands premium rates during the day.

In fact, this is the situation in the Pacific Northwest. The utilities there not only store water behind the dams during the night, but they actually purchase relatively expensive coal-generated electricity from other states at

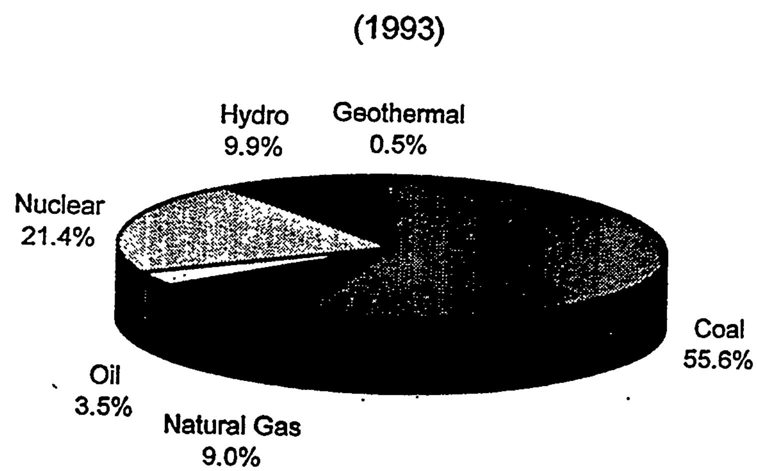


Figure 14. U.S. utility energy mix

[39] Cass Bielski, editor, *Typical Residential, Commercial and Industrial Bills*, Edison Electric Institute, Winter 1994.

night. One utility varies the output of one dam by seven to one, from 3,000 cfs at night to 21,000 cfs during the daytime peak.[40] It then sells its hydroelectricity during the day at higher prices, helping to ease the peak daytime loads. In other words, it is using the storage attributes of hydroelectricity to help alleviate peak loads, even though that means purchasing coal-generated electricity. The utility is better off financially purchasing coal electricity off peak and selling its hydroelectricity on peak. As a result, it does not have significant excess capacity during off-peak periods.[41]

This may change in the future, however, due to environmental concerns regarding fluctuating water levels. Regulations may be changed to protect the salmon runs by reducing the allowed water level changes on the Snake and Columbia Rivers, for example. If water levels are regulated in the future, then some utilities in the Pacific northwest might have excess capacity at night and might be interested in selling off-peak power at reduced rates.

During normal years, the Bonneville Power Authority (BPA), with 20 GW of installed hydro capacity (85% of its energy), has excess electricity during the spring months. Electricity rates can be as low as 1-2.5 cents/kWh wholesale, or 2-5 cents/kWh retail when the water levels are high. These low excess electricity rates do not depend on time of day—they are available at all times from April through July as long as the water levels on the Columbia River are high. But water levels are currently low after 6 to 8 years of drought, so even these spring hydroelectricity bargains are not reliable.[42]

Other sources of renewable electricity are even less attractive today. Wind energy is the most well-developed renewable, but wind electricity still costs 5-7 cents/kWh, above our goal of less than 3.5-4.5 cents/kWh. Solar thermal costs are estimated slightly higher at 6-8 cents/kWh, while photovoltaic (PV) solar cells are well above 15- 20 cents/kWh by most accounts. The most ambitious near-term projection for PV is the rumored plan by ENRON and AMOCO to install 100 MW of amorphous silicon PV systems in Nevada that could produce electricity at 5.5 cents/kWh -- a very promising development on the path toward inexpensive renewable electricity, but still above our near-term goal of less than 3.5-4.5 cents/kWh.

The least costly renewable hydrogen would probably come from biomass in the near term. Crops grown specifically to produce energy could be cost effective within a decade and could provide a hedge against excessive greenhouse gas emissions as we enter the 21st Century. But hydrogen can be produced directly from such biomass by gasification, without going through the intermediate step of combustion to boil water to run a steam generator to produce electricity for electrolysis. One promising proposal would gasify switchgrass to produce hydrogen directly, which could then be used to power farm machinery or off-farm vehicles. The hydrogen could also produce electricity on the farm with a fuel cell stack.

Because inexpensive hydroelectricity is either non-existent or available only during the wet spring months in the Pacific Northwest, and because other renewable electricity options are too expensive, the only economic alternative for early hydrogen electrolyzer demonstrations is off-peak electricity from the existing mix of utility-generating capacity.

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[40] Private communication, Dan Fifer of Washington Water Power Company, November 30, 1994.

[41] Private communication, Dave Clement of Pacificorps, November 21, 1994.

[42] Private communications with Barney Keep (November 22, 1994) and John Hyde (November 23, 1994) of the Bonneville Power Administration.

3.2 Electrical Demand Profiles

The electric utility industry must supply very reliable electricity under widely fluctuating load conditions. Loads vary by factors of two or more between the peak levels during a hot August afternoon, when all air conditioners are running, and the reduced demand in the early morning hours year around. Electrical demand also varies by season, particularly in the southern and western regions of the country.

To provide reliable service during peak-load periods, state public utility commissions require utilities to maintain a spinning reserve—generating capacity to provide virtually instantaneous power as needed—as well as a reserve margin to add generating capacity over and above the expected peak load. In some cases, small utilities can borrow electricity from neighboring utilities that have excess capacity, but the industry in general must still install sufficient generating capacity to meet the peak loads plus a specified margin to meet unexpected demands or to cope with unexpected failures of generating or transmission equipment.

As a result of this requirement for excess generating capacity during peak demand periods, utilities by definition have excess capacity most of the time. Hence, they have underutilized capital equipment. Much of this excess capacity during the peak periods is provided by older generating equipment that is too costly to run continuously as baseload capacity. In general, utilities will run generators with the lowest operating costs full time, bringing on more costly generators in ascending order of operating cost as needed throughout the day or season.

This excess capacity grows significantly as the customer demand for electricity declines during the night or during the off-season. During these off-peak periods, the utilities may be able to sell only 30% to 40% of their electrical capacity. They may not even be able to sell all the electricity generated by their equipment with the lowest operating costs. Under these conditions, some utilities are willing to offer electricity at very low rates. Any electricity sold at rates above the utilities' operating costs will help to recover their capital costs. This is the opportunity we have explored for very inexpensive electricity to produce hydrogen.

While inquiring about current utility load profiles, we learned that all utilities are required to report their hourly load demand to the Federal Energy Regulatory Commission (FERC) on a "Form 714." These data are now available electronically from FERC. We downloaded these data by modem, and have plotted representative load profiles in Figures 15 through 29 to illustrate general utility load requirements across the country.

For each utility in our small sample, we averaged the electrical load over each 24-hour period for the months of January and February, 1993, as representative of the winter utility load. We averaged and plotted weekdays and weekends separately. We then repeated the same process for the months of July and August, 1993, to represent typical summer load profiles. On each plot, we included the absolute peak load for the year, along with the calculated ratio of the minimum average load (averaged over the 2-month period) to the peak load.

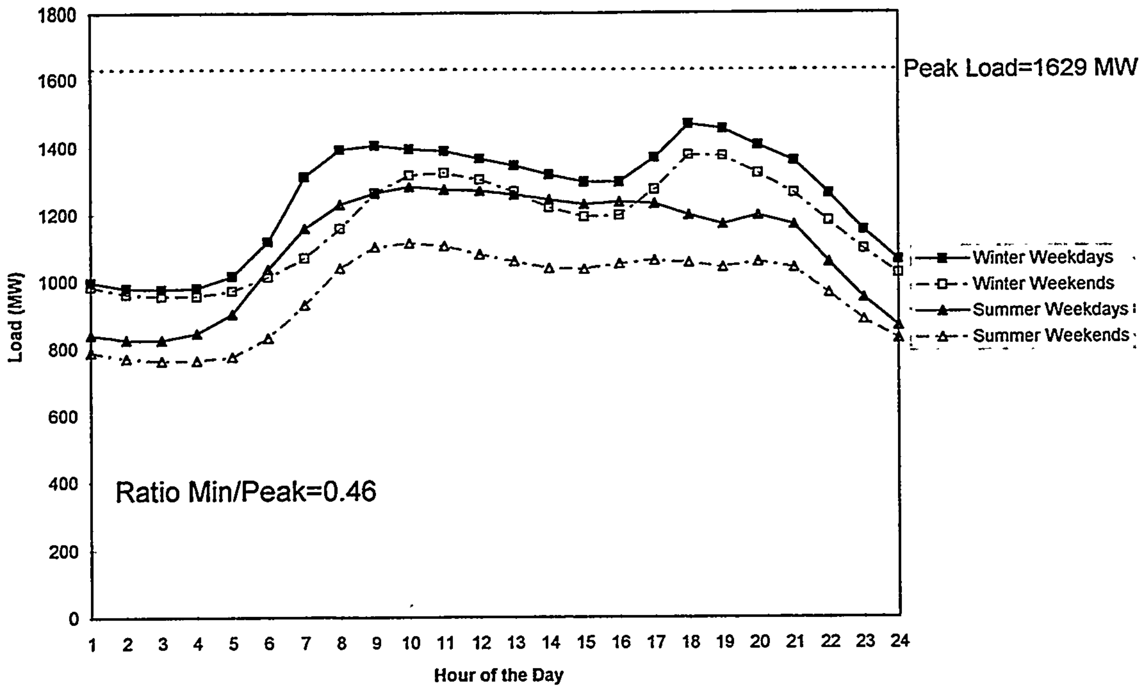

Figure 15. Central Maine Power Company, seasonal load profiles (1993)

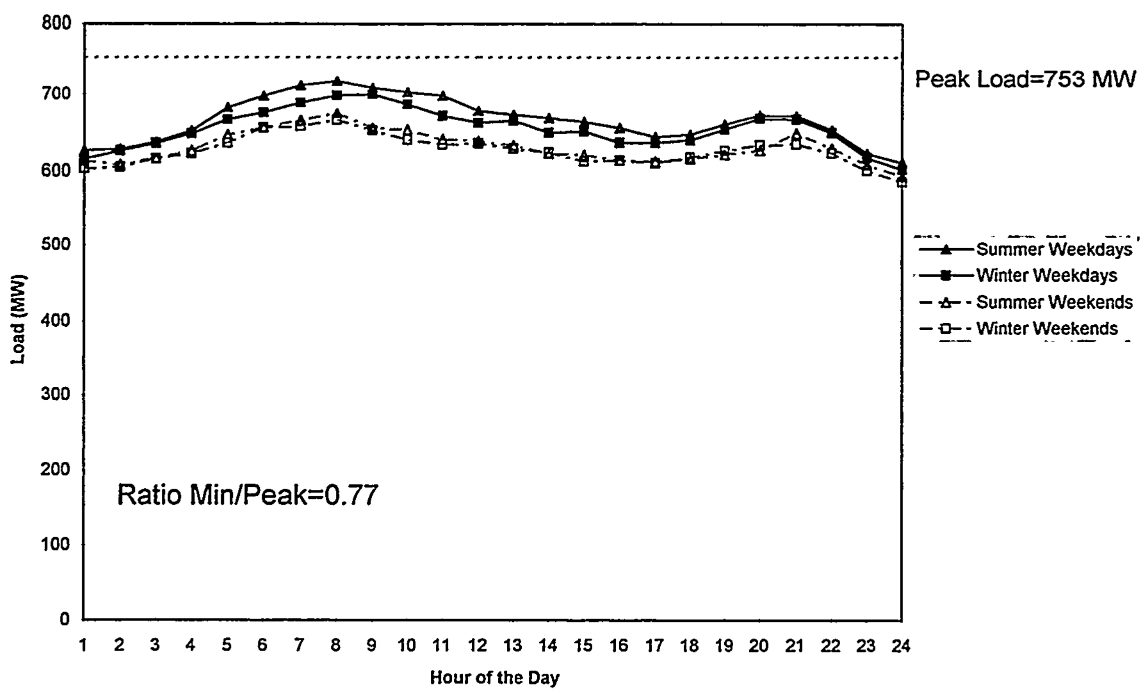

Figure 16. New York Power Authority, seasonal load profiles (1993)

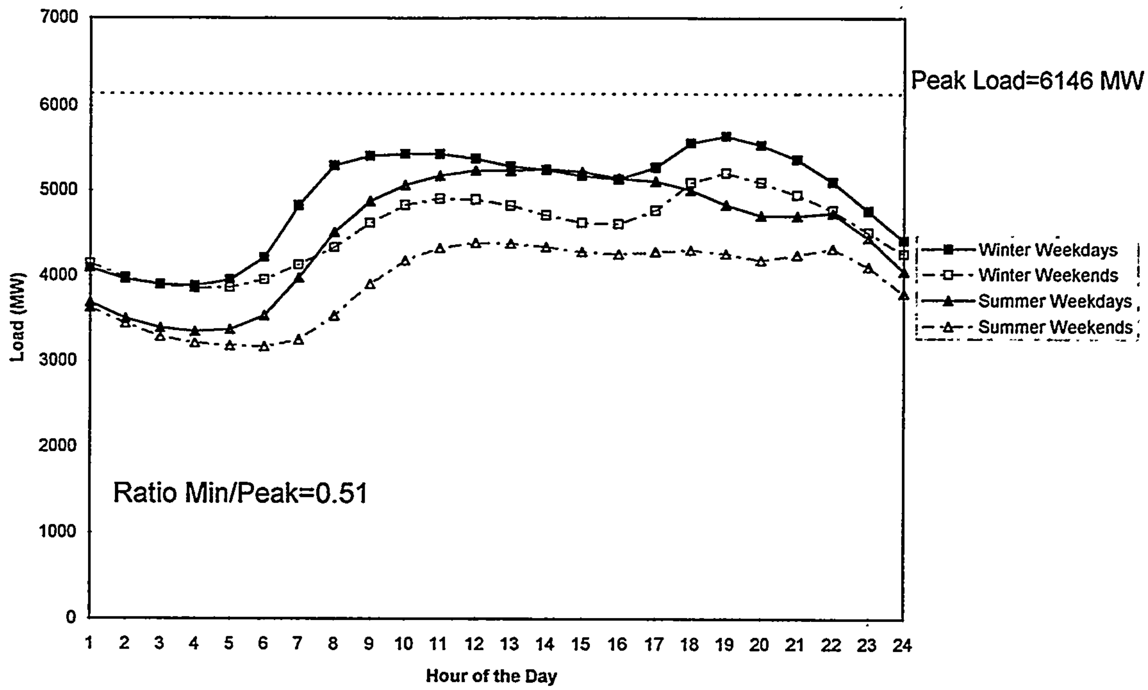

Figure 17. **Niagara Mohawk Power Corporation, seasonal load profiles (1993)**

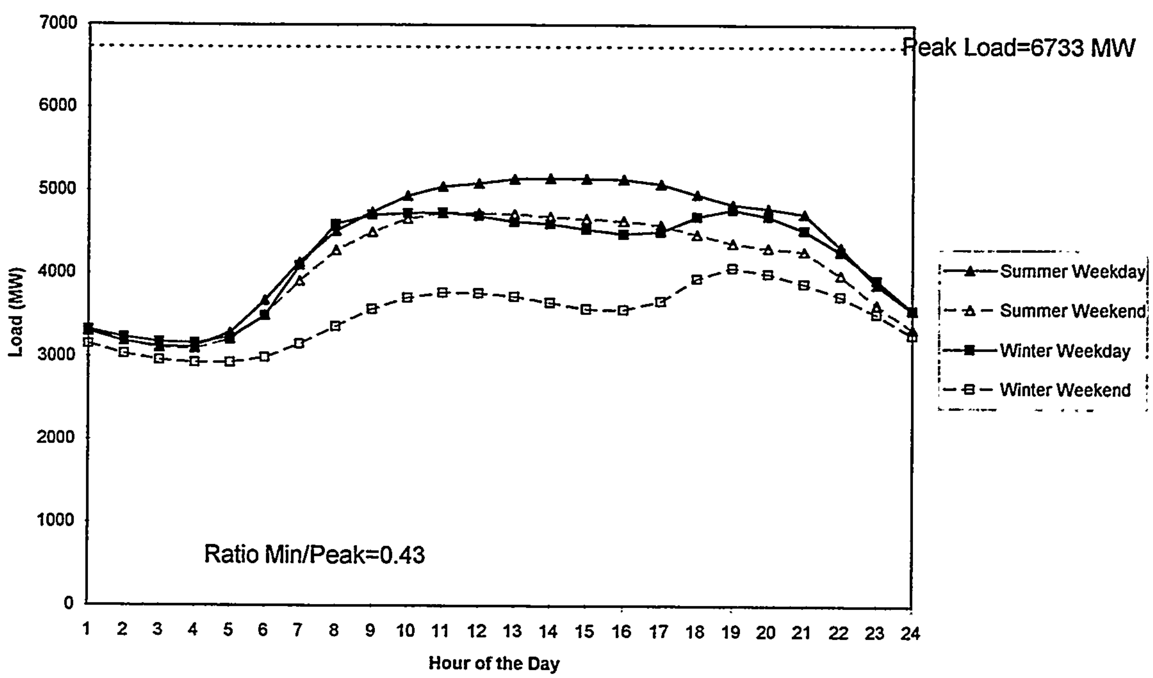

Figure 18. **Northern States Power Company, seasonal load profiles (1993)**

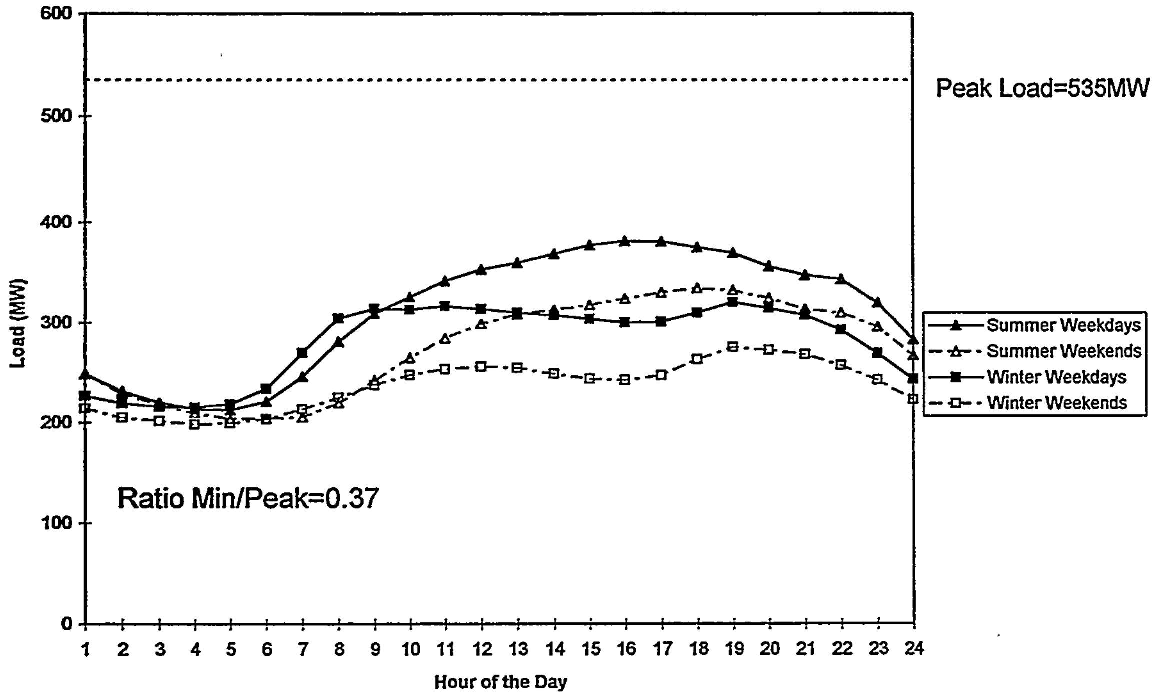

Figure 19. Lincoln Electric System, seasonal load profiles (1993)

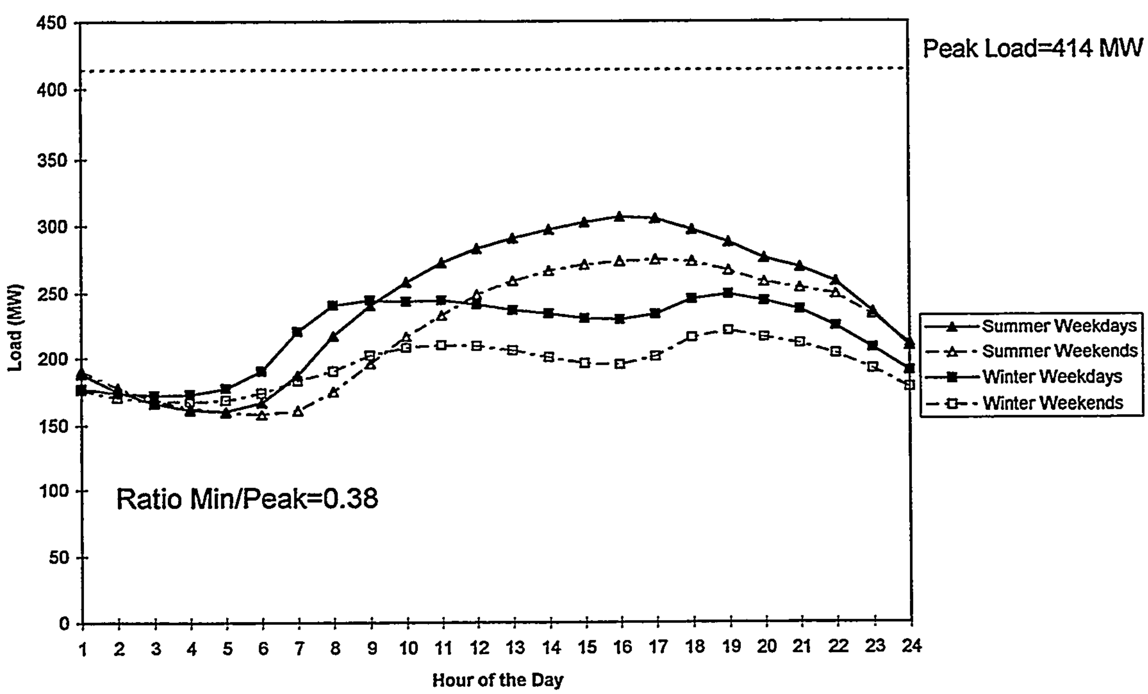

Figure 20. Springfield City Water, Light & Power, seasonal load profiles (1993)

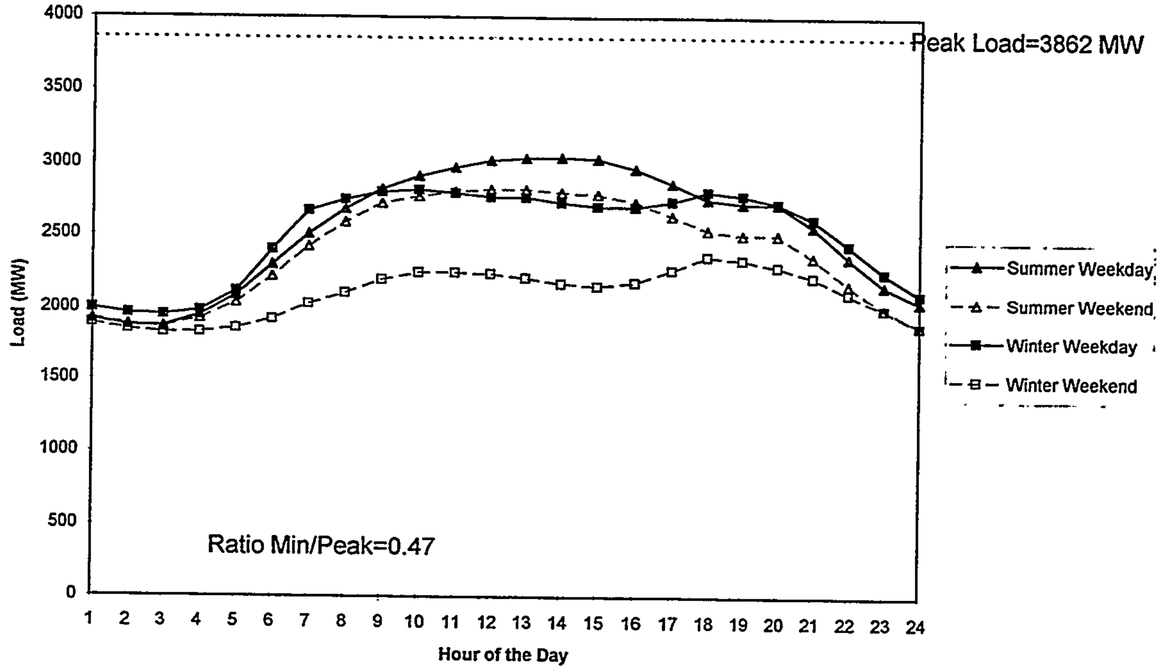

Figure 21. Cleveland Electric Illuminating Company, seasonal load profiles (1993)

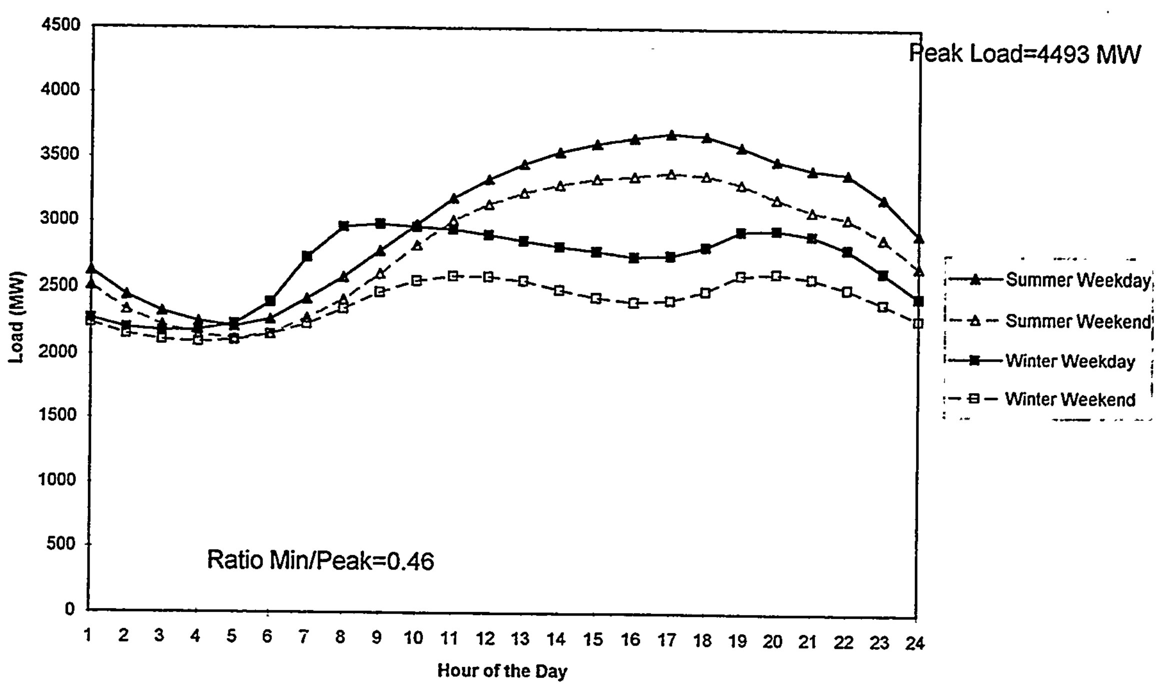

Figure 22. Cinicinnati Gas & Electric, seasonal load profiles (1993)

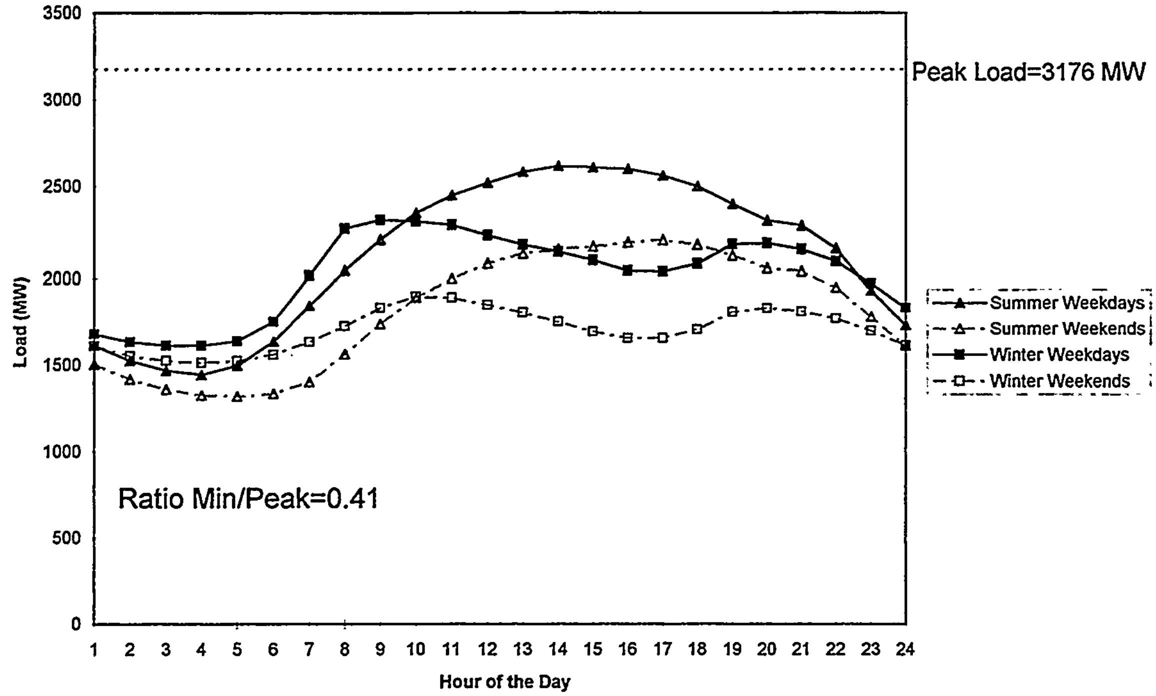

Figure 23. Kentucky Utilities Company, seasonal load profiles (1993)

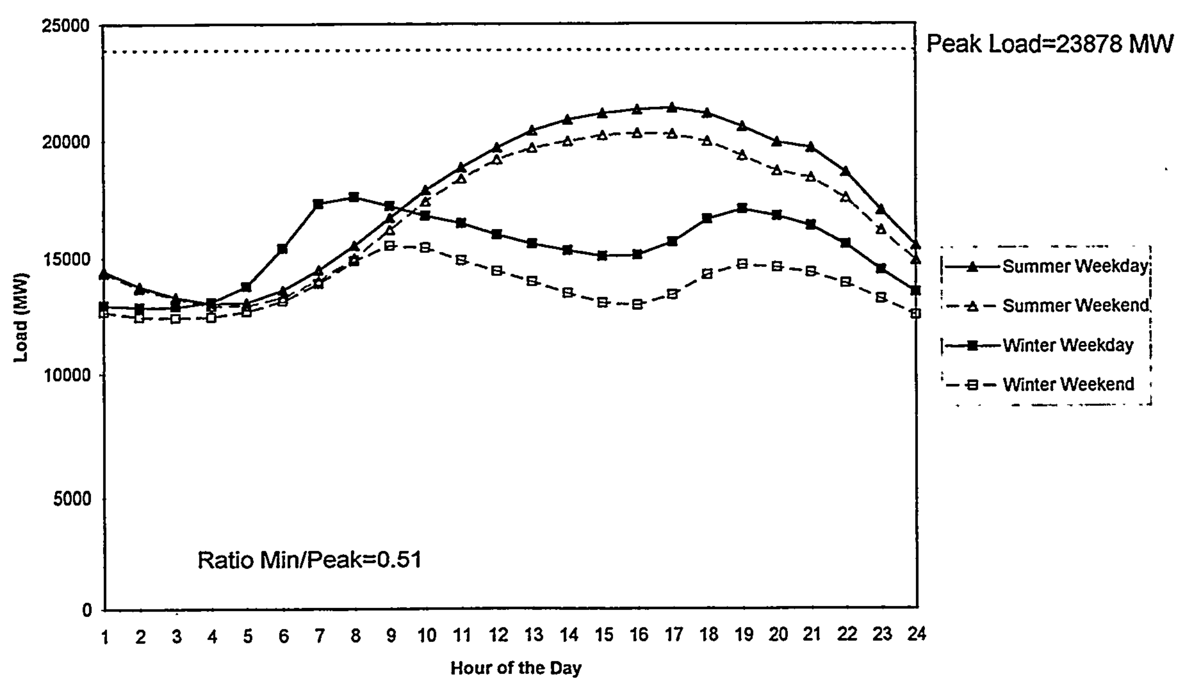

Figure 24. Tennessee Valley Authority, seasonal load profiles (1993)

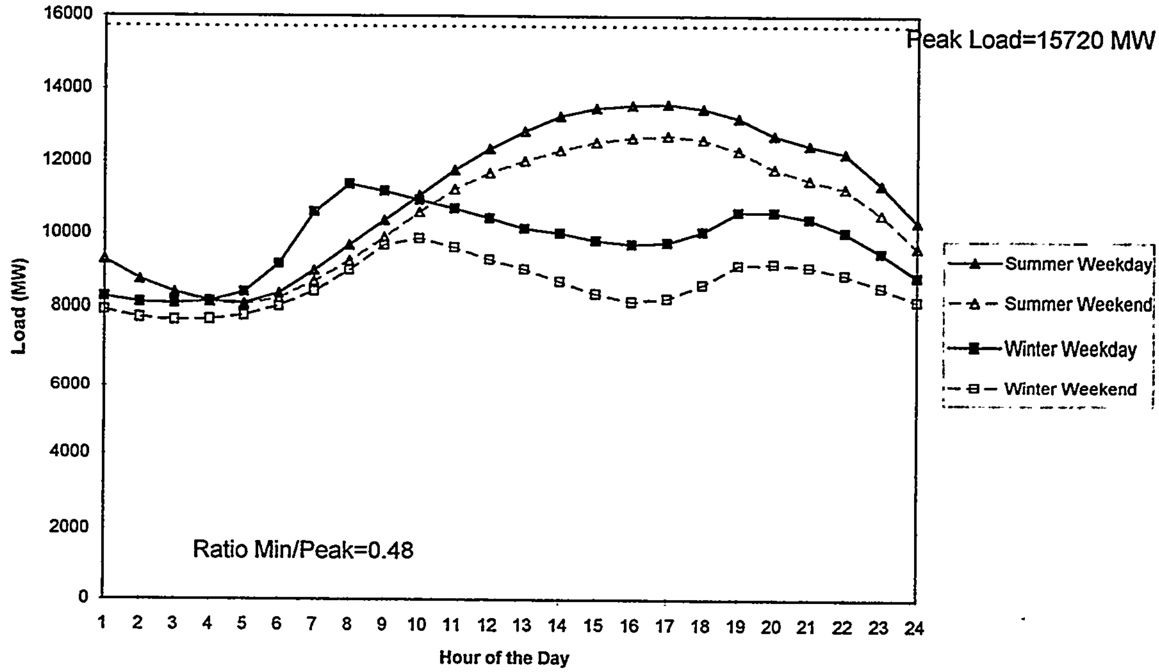

Figure 25. Duke Power, seasonal load profiles (1993)

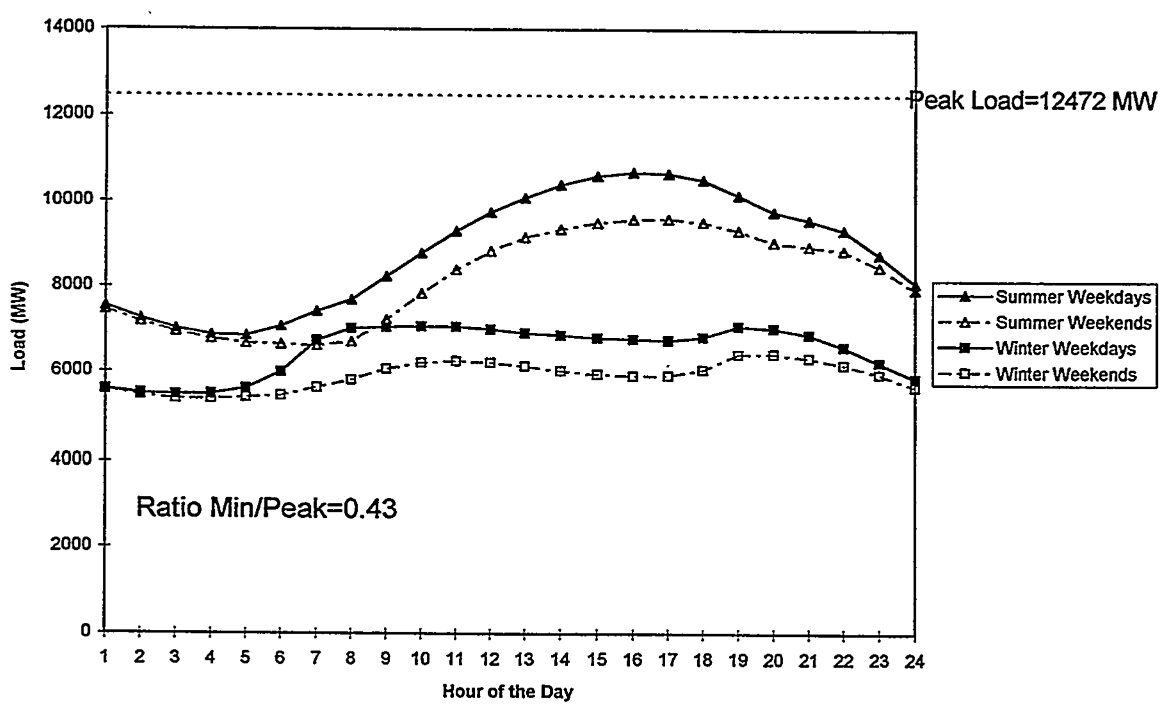

Figure 26. Houston Lighting & Power, seasonal load profiles (1993)

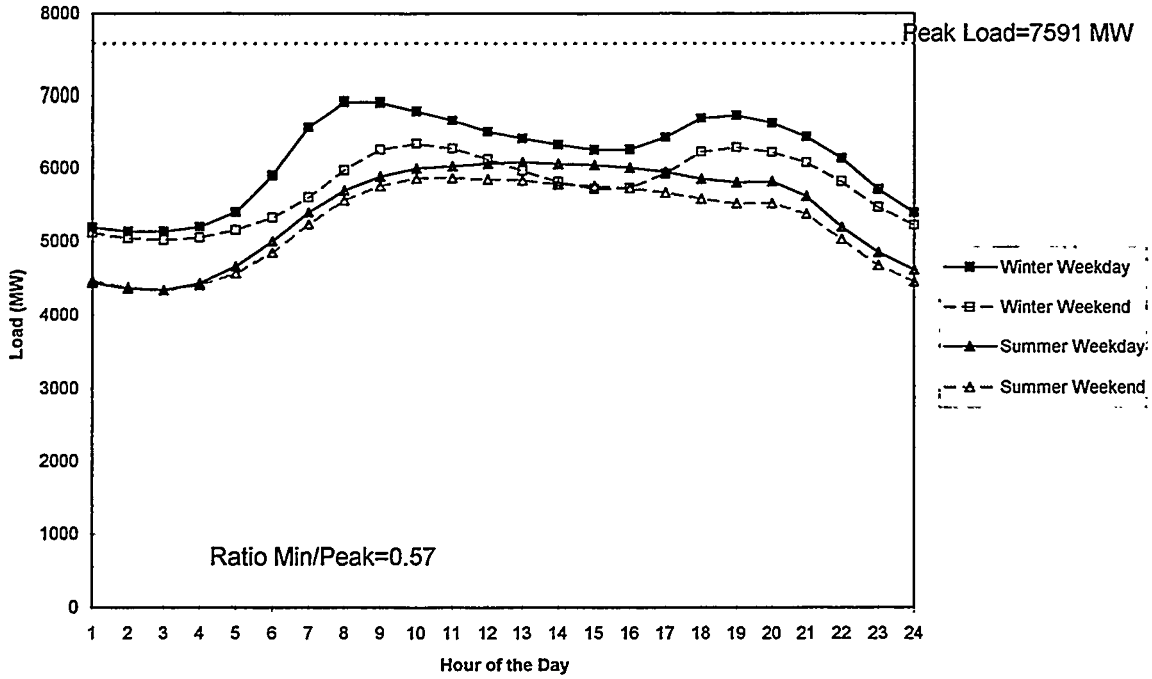

Figure 27. PacifiCorp (Pacific Northwest), seasonal load profiles (1993)

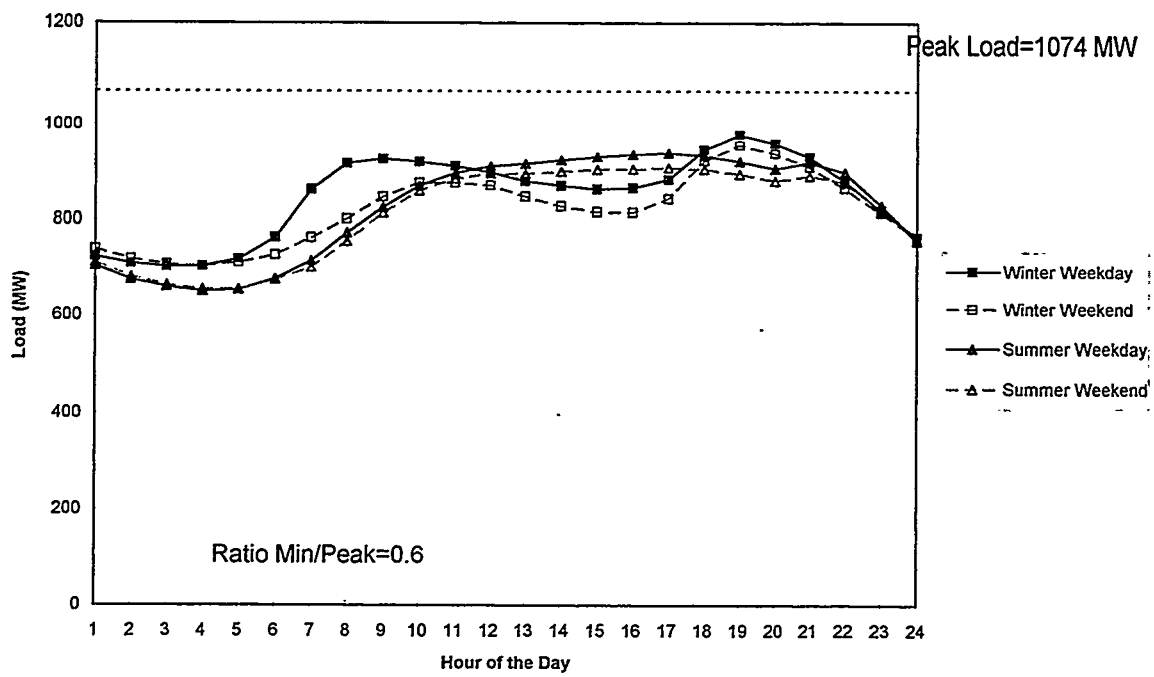

Figure 28. Sierra Pacific Power Company, seasonal load profiles (1993)

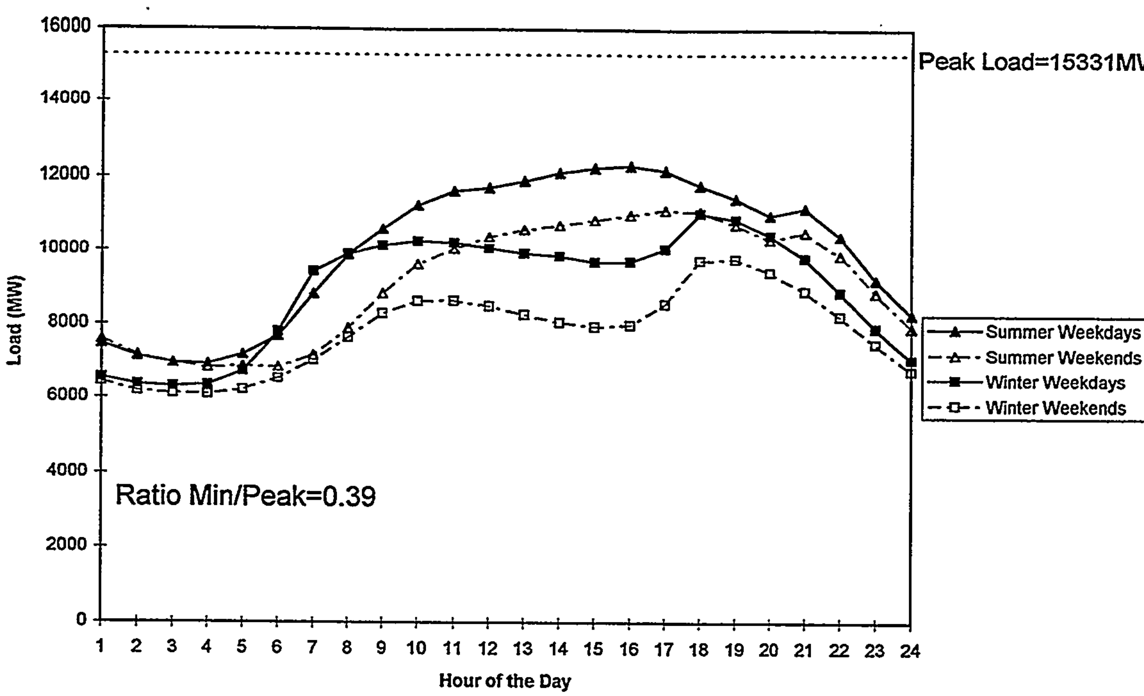

Figure 29. Pacific Gas and Electric, seasonal load profiles (1993)

Beginning in the eastern United States, Figure 15 shows the load profiles for the Central Maine Power Company. This is a typical winter-peaking utility. The winter load profile is characterized by a double peak: one around 8:00 to 9:00 am and the other between 5:00 and 7:00 pm as workers arrive home. The peak load of 1629 MW is well above the average winter peak, and the minimum average load (which occurs for summer weekends for this utility) is only 46% of the peak load. During summer nights, the Central Maine Power Company needs only 46% of the electricity it supplied during the peak hourly period for the year. However, this underestimates the utility's excess capacity, because it is required to provide reserve margin above its expected peak load.

Moving south along the east coast, Figure 16 shows the New York Power Authority, which has the flattest load profile of any of the utilities we sampled. There is very little load change from day to night or from Summer to Winter, with an average minimum-to-peak ratio of 77%. About 74% of the New York Power Authority generating capacity comes from the Niagara Falls hydroelectric plants, 19% from nuclear, 4.5% from natural gas, and 2.1% from oil.[43] In effect, the Power Authority "load curve" is really a supply curve, indicating the nearly constant output from the Niagara hydro plants and two nuclear power plants. In fact, investor-owned utilities in New York are required to purchase power from the Authority,[44] so this is not really a typical load profile.

The Niagara Mohawk Power Corporation load is more representative of the actual load of an investor-owned utility in the New York area. As Figure 17 illustrates, the gap between summer and winter average peaks has narrowed compared to Maine, but the winter peaks are still slightly higher.

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[43] *Electric Power Monthly*, Energy Information Administration, U.S. Department of Energy, April 1994, p. 226.

[44] Private communication with Terry McHugh of the Niagara Mohawk Power Corporation on November 7, 1994.

Figures 18 through 26 show a sampling of utilities in the midsection of the country, from Northern States Power Company to the Houston Lighting and Power Company. Similarly, Figures 27 through 29 show a sampling of utilities on the West Coast.

In general, the average minimum-to-peak ratios run from 40% to 50%, with the separation between summer and winter peaks growing as one moves south. Almost all utilities are characterized by a large gap between peak load and night-time load, often approaching 50% even for the highest demand off-peak periods. We conclude that almost all utilities have excess off-peak capacity and infer that most could recover capital costs if they could sell extra electricity during these periods above their marginal costs.

3.3 System Lambda

In addition to hourly load data, most utilities are required to provide FERC with hourly data on "system lambda." System lambda is essentially a measure of a utility's marginal operating cost—the cost of fuel and other maintenance costs associated with adding extra electrical output at any instant of time—in miles/kWh. Utilities use these system lambda data to provide for virtually instantaneous dispatch of electrical power in response to demand within a given region.[45] If the load increases in a region, then the utility will turn on the idle generator with the lowest system lambda, thereby minimizing system operating costs. The most costly generators are saved for last, operating rarely if at all. Not all generators are required to follow this method of economic dispatch, however. In particular, hydroelectric plants with very low marginal costs are managed to optimize their storage contributions to shaving the peak load, as discussed earlier, or sold as baseload if storage is not an option. Some utilities also belong to a larger power pool, and are not required to report their individual system lambda data.

A sampling of system lambda data are plotted in Figures 30 through 40. In general, system lambda data fluctuate much less than load profiles on either an hourly or seasonal basis. Most utilities sampled have an average system lambda below 2 cents/kWh. Nighttime rates are consistently below 2 cents/kWh (except for the West Coast), and sometimes below 1.5 cents/kWh, particularly in the winter months.

Based on this data, we conclude that many utilities could recover some of their capital investment and still provide home electrolyzers with electricity below 3 cents/kWh during off-peak periods.

At least two utilities have applied for and received permission to provide "real-time pricing" rates to selected customers: Florida Power & Light and the Southern California Edison Company (SCE). The SCE rate structure is for large industrial or commercial users and provides at best a rate around 7-8 cents/kWh in the early morning hours, depending on the previous day's temperature. This rate rises to as much as \$3.05/kWh (dollars, not cents/kWh!) during the afternoon if the previous day's maximum temperature exceeded 95°F. Clearly, this rate is not conducive to cheap electrolytic hydrogen.

Florida Power & Light's real-time pricing experimental rate tariff went into effect on February 1, 1995, and extends until December 1998.[46] This tariff essentially adds from 1 to 1.5 cents/kWh to the system lambda operating cost. During those rare periods when the load actually approaches the peak generating capacity, extra reliability charges could push these rates as high as several *dollars* per kWh, but these extraordinary rates might

[45] Private communication with William C. Booth of the Federal Energy Regulatory Commission on October 31, November 4, and December 19, 1994.

[46] Private communications with Bob Bergstrom (October 31, 1994), Bob Suggs (December 19, 1994) and Tom Tramutola (December 19, 1994) of the Florida Power & Light Company.

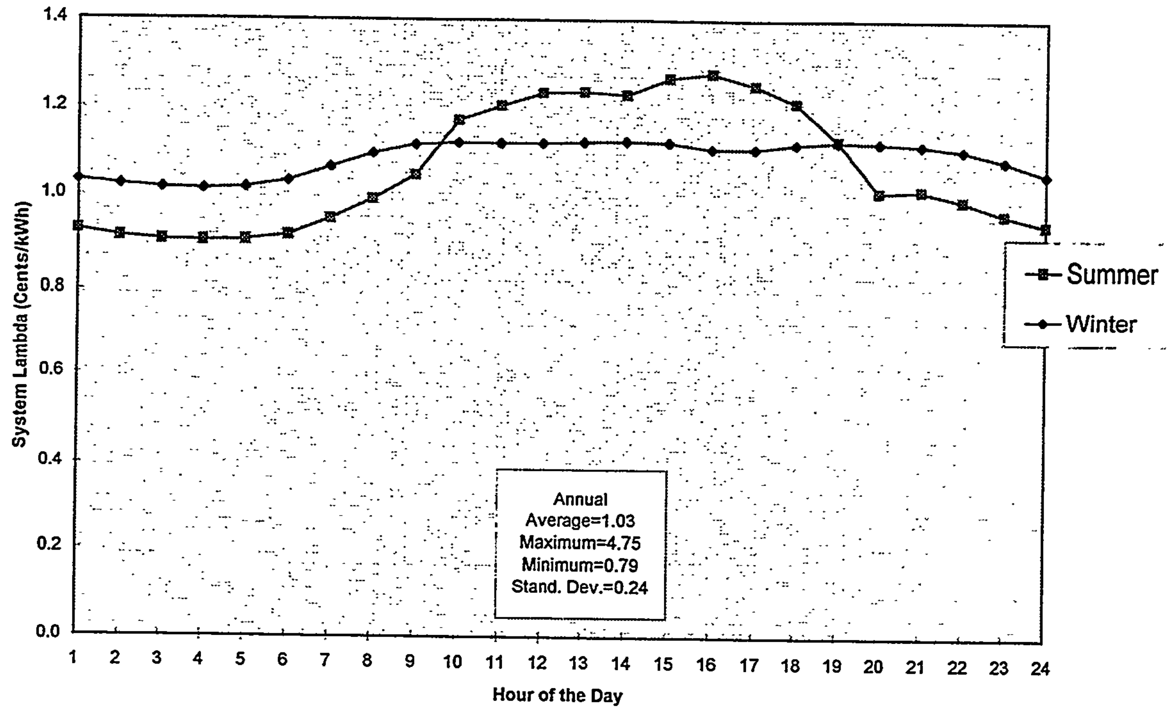

Figure 30. Northern States Power Company, average system lambda or marginal operating cost

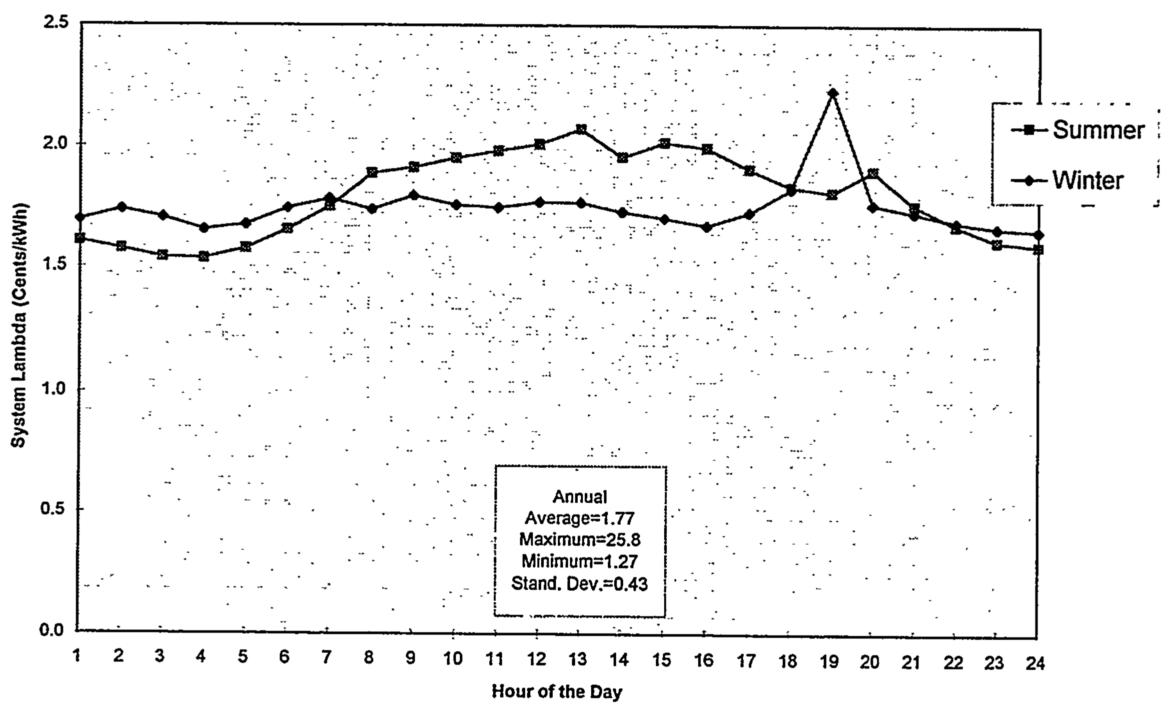

Figure 31. Southern Indiana Gas and Electric, average system lambda or marginal operating cost

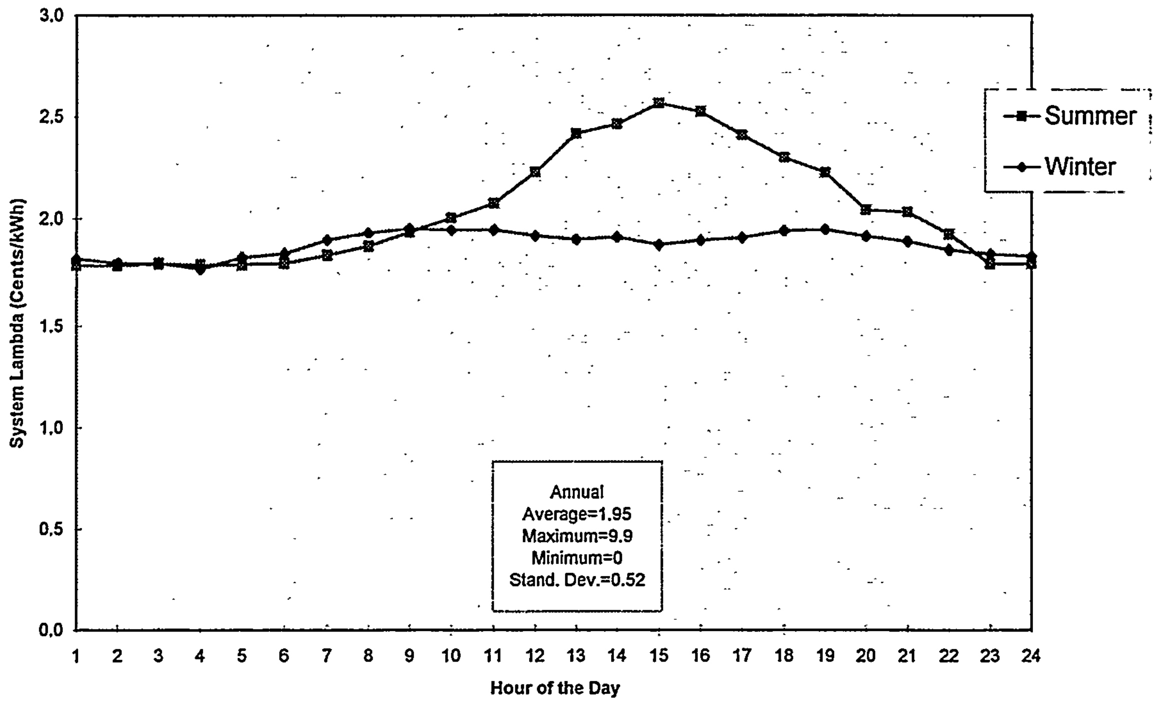

Figure 32. Cleveland Electric Illuminating, average system lambda or marginal operating cost

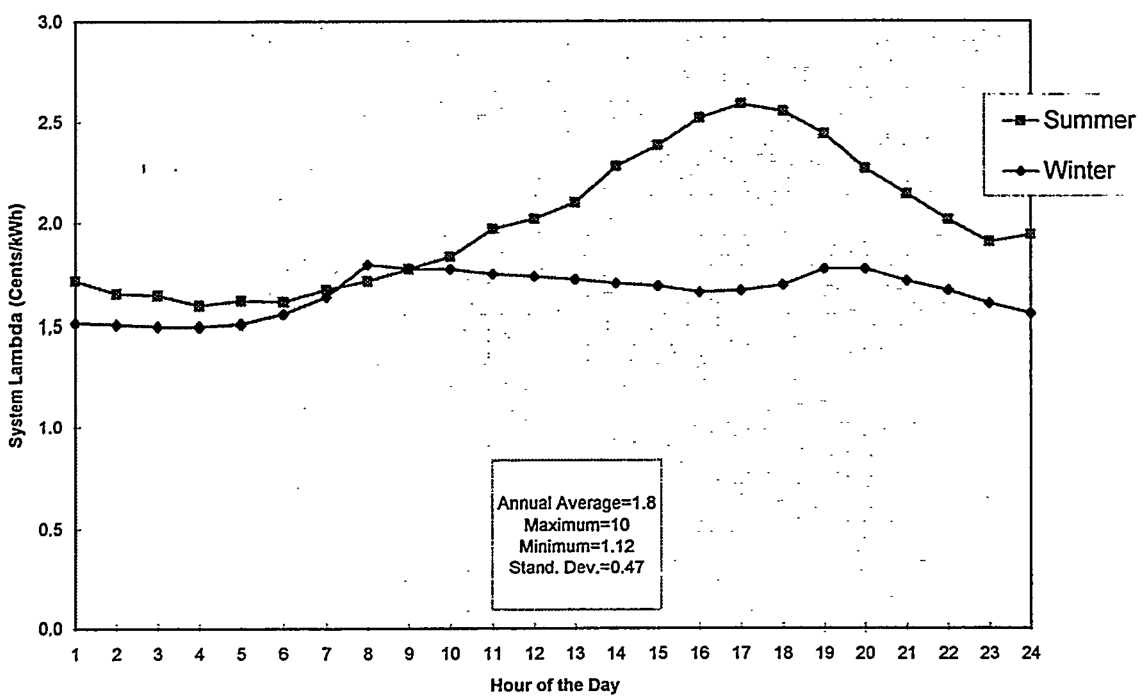

Figure 33. Cincinnati Gas and Electric, average system lambda or marginal operating cost

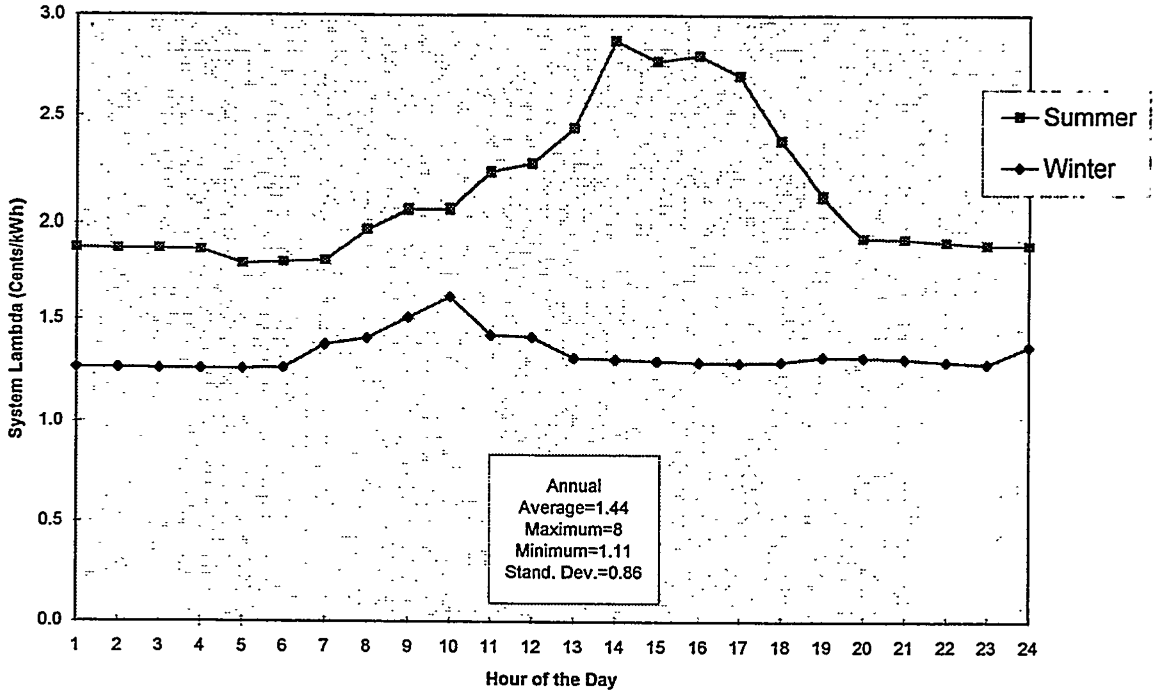

Figure 34. Kentucky Utilities Company, average system lambda or marginal operating cost

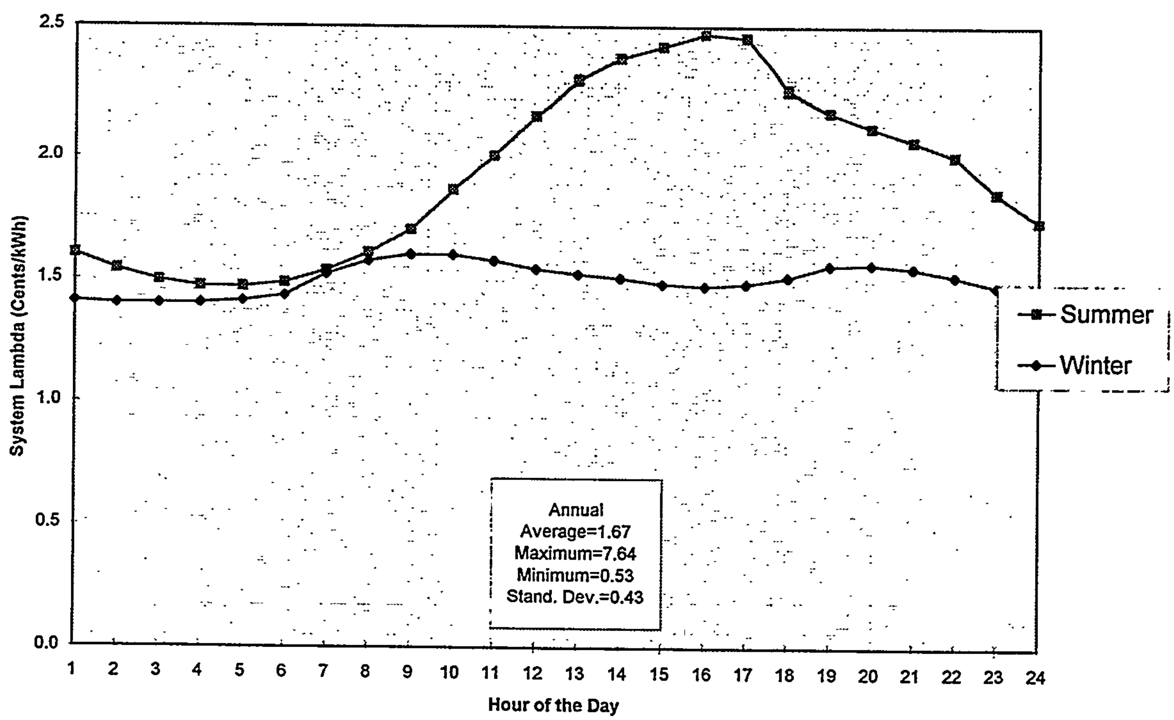

Figure 35. Duke Power Company, average system lambda or marginal operating cost

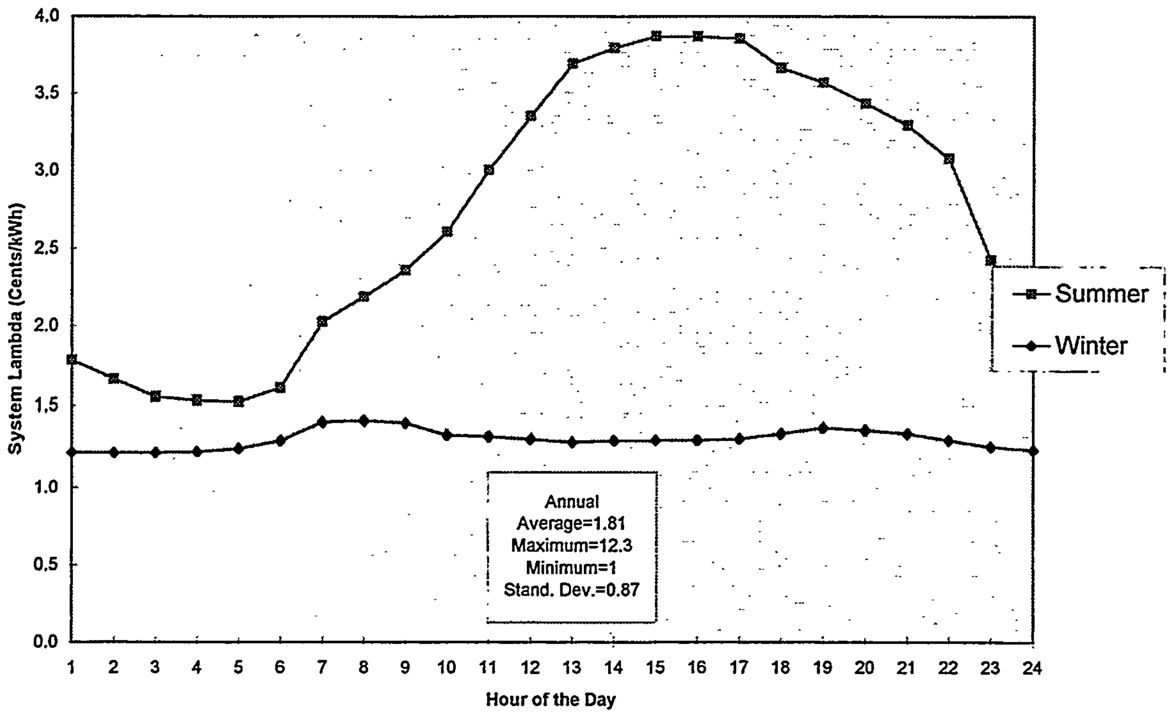

Figure 36. Tennessee Valley Authority, average system lambda or marginal operating cost

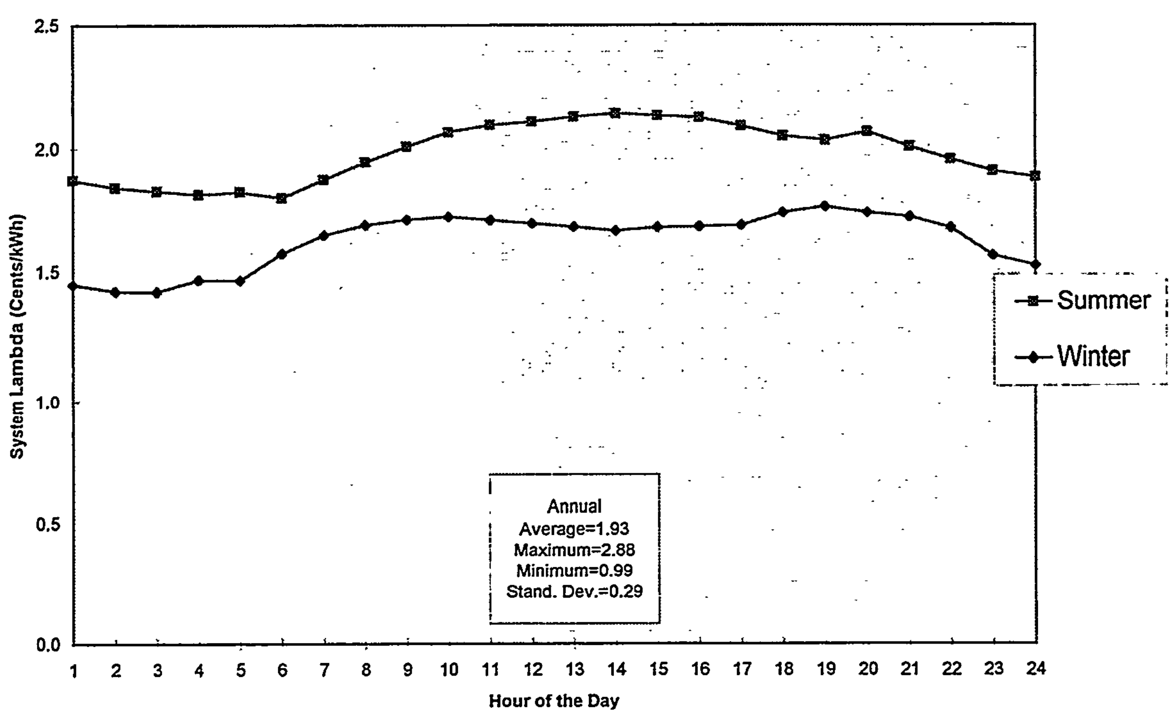

Figure 37. Houston Lighting and Power, average system lambda or marginal operating cost

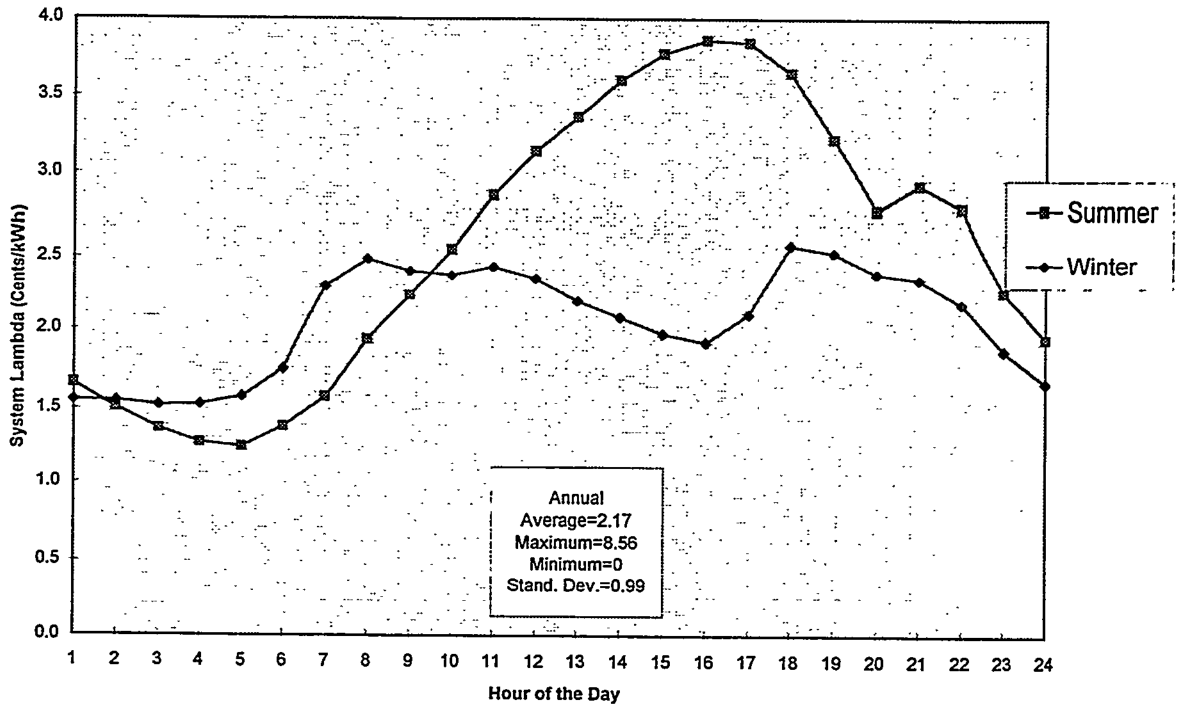

Figure 38. Pa-NJ-Md Interconnect, average system lambda or marginal operating cost

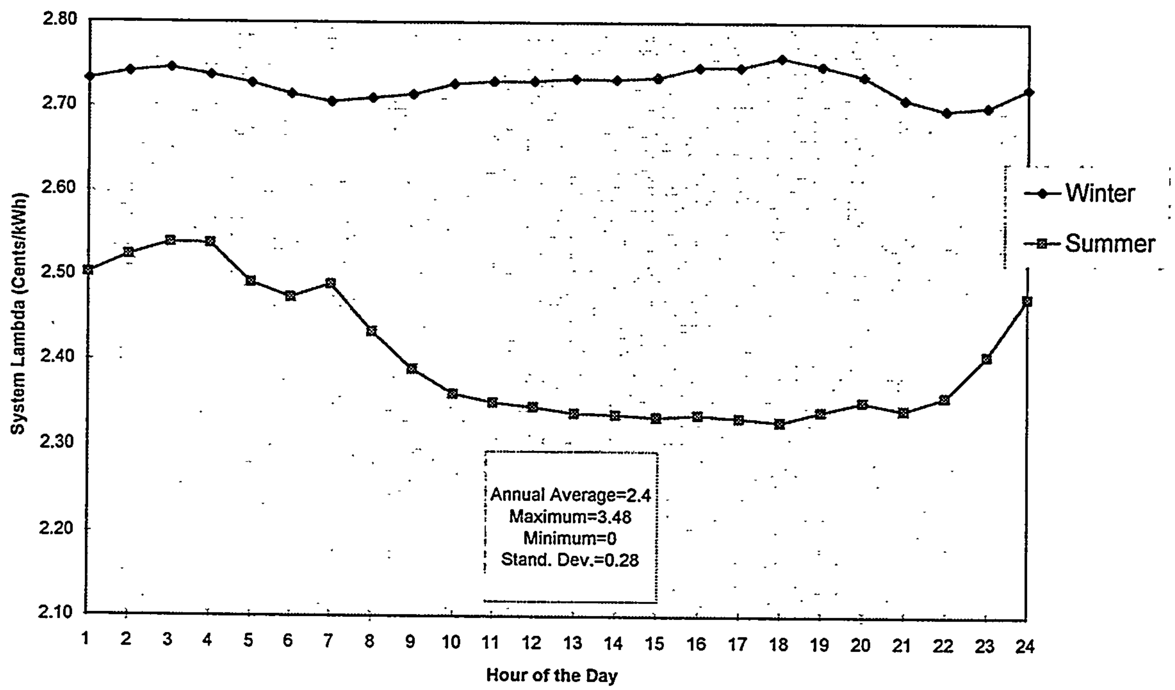

Figure 39. Sierra Pacific Power Company, average system lambda or marginal operating cost

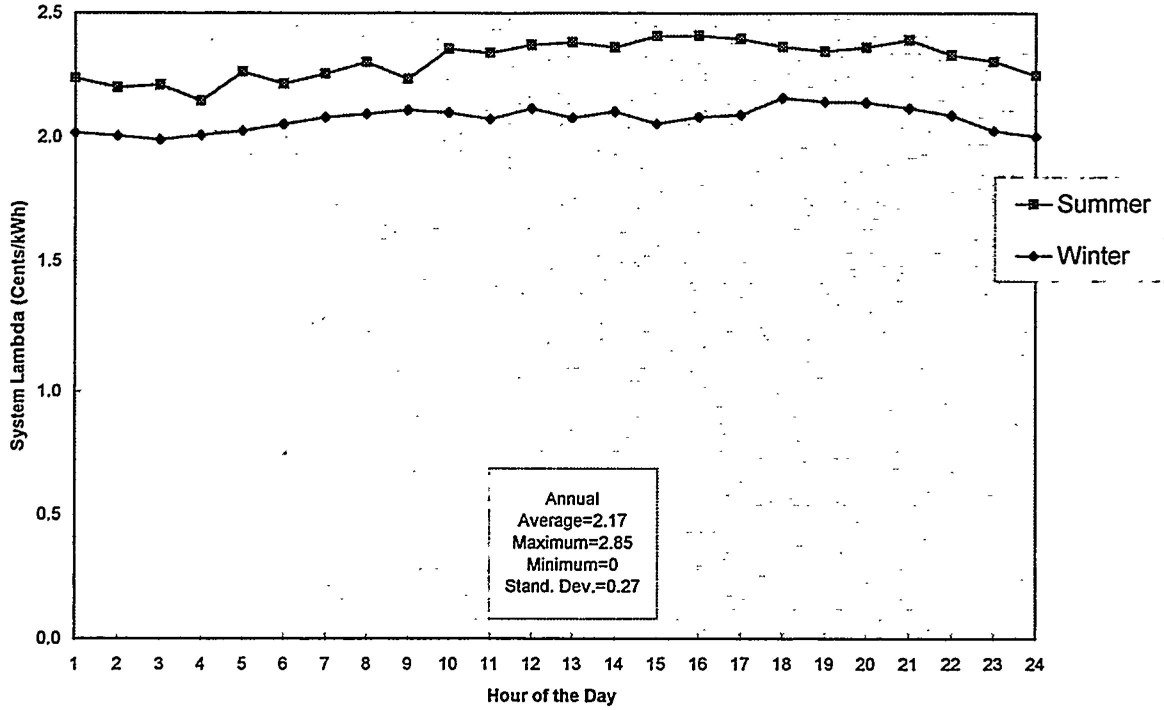

Figure 40. Southern California Edison, average system lambda or marginal operating cost

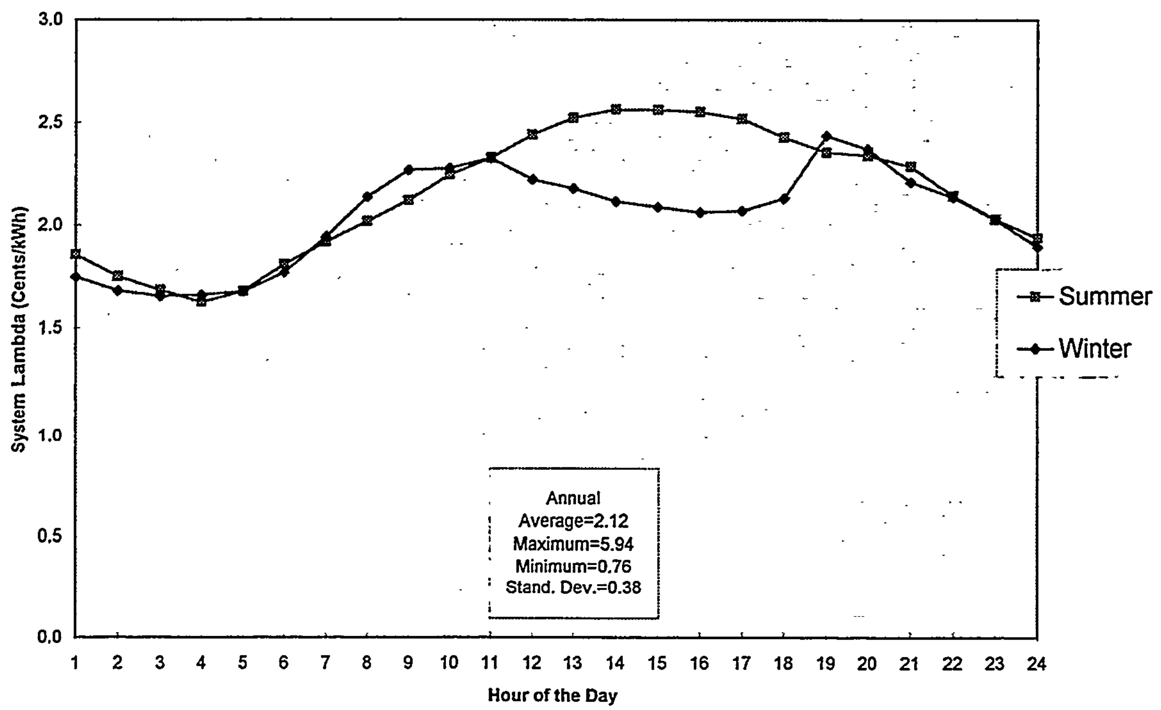

Figure 41. Florida Power and Light Company, average system lambda or marginal operating cost

only occur once every few years. During off-peak periods, the rates would be only 1-1.5 cents/kWh above system lambda.

Florida Power & Light does have system lambda costs somewhat higher than other utilities that we sampled in this brief study, averaging 2.12 cents/kWh, as shown in Figure 41. Higher operating costs may be due to the heavy reliance on oil-generated electricity: about 43% of Florida Power & Light electricity comes from oil, 35% from nuclear, and 23% from natural gas.[47] The utility paid an average of $2.21/MBTU for oil in 1993,[48] which is equivalent to about 2.1 cents/kWh assuming 35% efficiency for an oil-burning utility plant, while natural gas cost $2.22/MBTU or 1.89 cents/kWh at 40% efficiency.

Adding 1-1.5 cents/kWh to the system lambda cost of 2.12 cents/kWh would raise the price to the owner of a home electrolyzer to 3.1-3.6 cent/kWh, which would meet our goal of less than 4.5 cents/kWh for initial introduction of electrolytic hydrogen. However, the Florida Power & Light tariff, as currently written, apparently applies only to existing industrial customers with established energy use patterns. It is not clear how a home owner or a fleet operator would qualify for real-time pricing as currently written.

Nonetheless, this tariff does suggest that other utilities might benefit from selling electricity at rates 1-1.5 cents/kWh above system lambda. If Northern States Power Company, with an average annual system lambda of only 1.03 cents/kWh, offered a similar rate structure to encourage hydrogen production by electrolysis to new customers, then we could expect off-peak rates in the range of 2-2.5 cents/kWh.

3.4 Current Off-Peak Rates

We do not have to wait for new rate structures to begin producing electrolytic hydrogen at competitive prices in some sections of the country. Many utilities already offer off-peak rates below 4.5 cents/kWh.

In our discussions with various utilities and utility organizations, we discovered a publication that lists all of the current rate structures for most major investor-owned utilities.[49] These rate structures can be very complex. Some utilities offer more than 30 or 40 different rate structures for residential, commercial, and industrial customers. In general, industrial rates are the lowest, but also the most complex, because they include various "demand" charges in addition to energy charges. That is, the industry pays for energy per kWh consumed, but also pays a monthly charge depending on some measure of average or peak power used in kW. We did not have the opportunity on this small contract to explore the potential for these industrial rates to supply electrolytic hydrogen, but we did summarize the existing residential off-peak rates. Some individual rates reported below may be out-of-date, but they should be representative of what is currently available from electric utilities.

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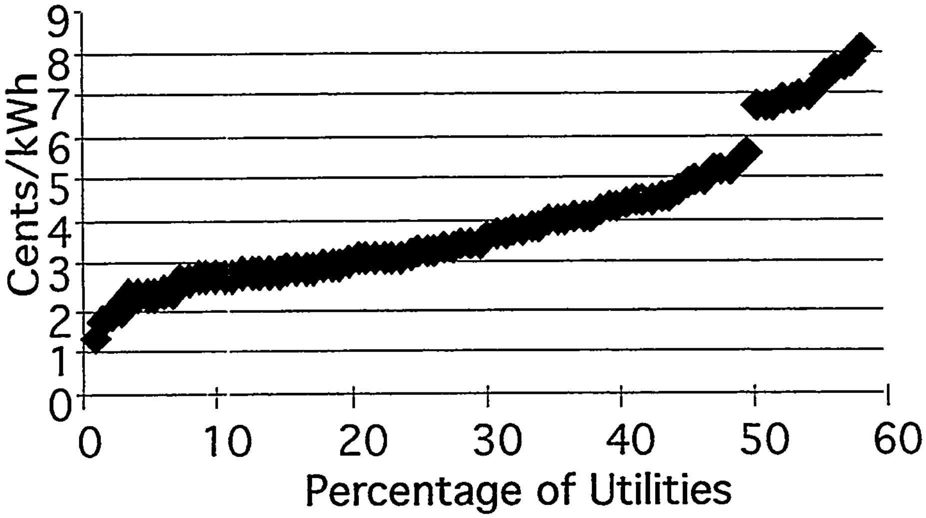
[47] Ibid., EIA, p. 195.

[48] Ibid, EIA, p. 255.

[49] *Electric Rate Book: Comprehensive Rate Information on Investor-Owned Electric Utilities*, published by Casazza, Schultz & Associates, Inc., Arlington, Virginia.



Source: Directed Technologies, Inc.

Figure 42. Off-peak residential electrical rates

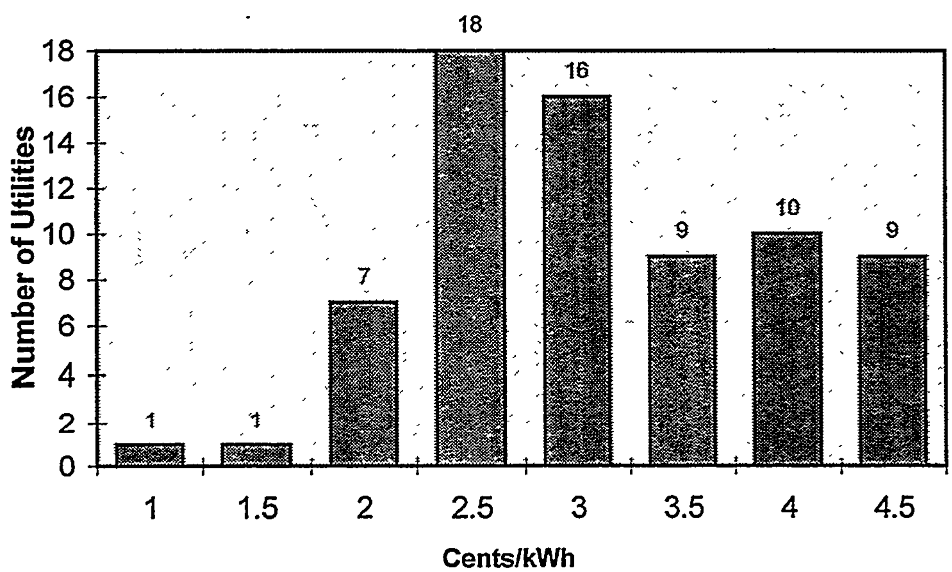


Figure 43. Off-peak electricity distribution (residential retail rates)

Of the 154 utilities scanned in this study, 58% had some type of residential off-peak or "time of use" (TOU) rate, ranging from 1.4 cents/kWh[50] up to as much as 8 cents/kWh (see Figure 42). Seventy-one utilities offered off-peak rates below 4.5 cents/kWh and 27 offered rates below 3 cents/kWh, as summarized in Figure 43.

While off-peak TOU rates are low, the utilities generally raise the rates substantially during peak use hours. Virginia Power, for example, offers residential customers electricity at 2.92 cents/kWh off peak, but the rate jumps to 17.5 cents/kWh from 11:00 am until 10:00 pm on summer weekdays and from 7:00 am to 11:00 am plus 5:00 pm until 9:00 pm on winter weekdays, well above the standard rate of 8.17 cents/kWh. If the home owner had to pay 17.5 cents/kWh to run his air conditioner in the summer, then the effective cost of electrolytic hydrogen would be excessive. However, Virginia Power already has several thousand customers who continue to use regular rates for their household while installing a separate TOU rate for a garage or machine shop.[51] We assume that a home electrolyzer would be treated the same as an electric vehicle and would qualify for the TOU rates without affecting the rest of the household.

Many utilities also charge an additional monthly fee for the TOU rate, primarily to cover the cost of a separate meter. For example, Virginia Power charges an extra $5 per month for its TOU off-peak rates. For a two-car family consuming an average of 88 pounds of hydrogen per month, this would amount to an additional cost of about 5.7 cents per pound, which amounts to a 6% increase in cost for $1/lb hydrogen—a manageable charge.

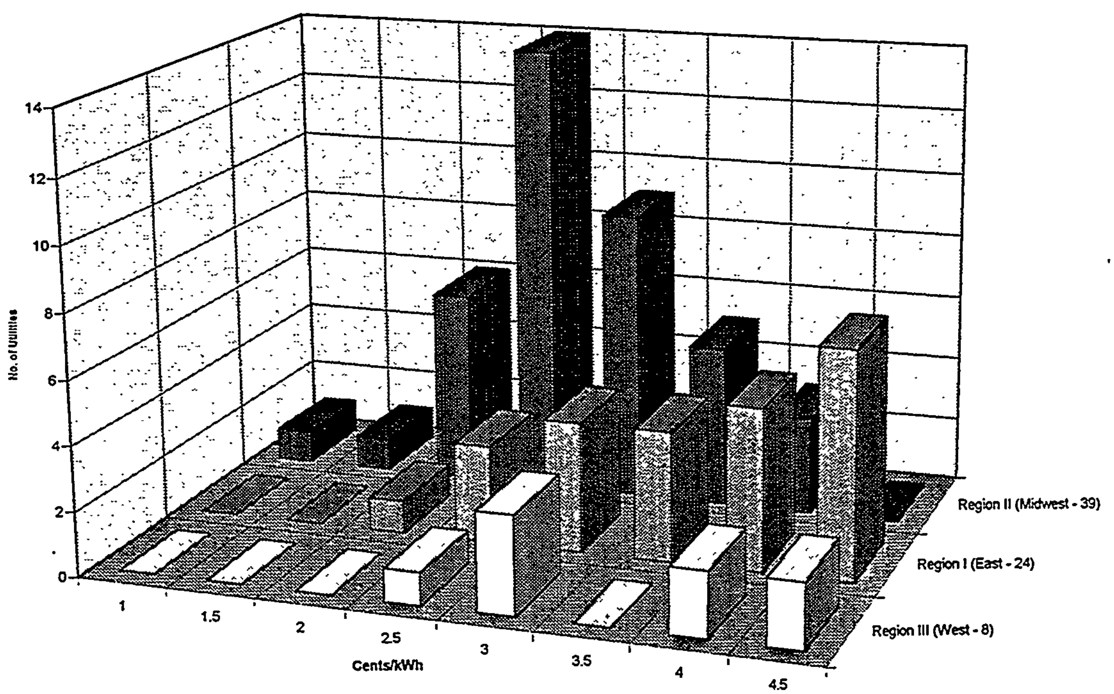


Figure 44. Off-peak electricity cost distribution (retail residential rates)

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[50] Alabama Power Company offered the lowest off-peak rate listed in the Electric Rate Book: from 9:00 pm until 10:00 am during summer weekdays, from 9:00 pm until 7:00 am during winter weekdays, and all day on weekends, Alabama Power Company offers a base rate of 1.25 cents/kWh, plus an energy charge that was 0.15 cents/kWh at the time of the report (March 31, 1994), or a total of 1.4 cents/kWh. The energy charge varies, depending on fuel costs, which allows the utility to pass on increased marginal costs to the customer.

[51] Private communication, Brett Crable, Virginia Power Company, March 27, 1995.

The geographic distribution of utilities with low off-peak rates was not uniform. Over half were located in the Midwest, as illustrated in Figure 44. Only eight utilities in the western region offered residential off-peak rates below 4.5cents/kWh.

3.5 Utility Excess Capacity

Some observers have questioned whether increased use of electricity to produce hydrogen would eventually consume the excess utility generating capacity, requiring the addition of more power plants. We calculated the increased demand for electricity under the following conservative assumptions. First, we assumed that all the zero emission vehicle (ZEV) requirements mandated in California would be supplied by FCEVs. Second, we assumed that all FCEVs would be fueled with electrolytic hydrogen. Third, we assumed that ZEV sales would continue at 10% per year after the California ZEV requirements expire. Finally, we assumed that six states (Massachusetts, New York, Maine, Maryland, and New Jersey) opted into the ZEV program, further increasing the demand for electrolytic hydrogen.

Under these optimistic assumptions regarding hydrogen vehicle market penetration, the cumulative FCEV fleet would amount to about 2.5 million vehicles in 2010, or about 2% of the U.S. car fleet. These 2.5 million FCEVs would consume about 2.7 billion kWh of electricity per month, which corresponds to about 5.9% of the electrical generation in the six states, or about 1% of the total U.S. electrical consumption.

Given that many utilities have excess capacity exceeding 50% of their output during half the day, an additional load of 1% to 6% by the year 2010 would have negligible impact.

A similar calculation was made by John Caskey of the Virginia Power Company. He estimated that if 10% of all new cars sold in Virginia each year were electric vehicles, then it would take *50 years* before their existing excess nighttime generation capacity would be utilized.[52] Clearly, the utility industry has sufficient excess capacity to supply FCEVs for several decades without adding any new generating equipment.

[52]Elaine Gaither and Mark Hopkins, Expanding the Markets for Alternative Fuel Vehicles in the Mid-Atlantic Region, The Alliance to Save Energy, December 1994, p. 8.

4.0 Conclusions

Based on this brief study of small electrolyzer systems and off-peak electrical rates, we have made the following conclusions:

1. Home electrolyzer systems could produce hydrogen for FCEVs that is cost competitive with fully taxed gasoline on a per-mile basis, provided that electrolyzers can be mass produced at less than $\$300/kW_{out}$ with compressors less than $\$115/kW_{out}$ and storage tanks less than $60/pound of hydrogen stored at 6,000 psi, and provided that electricity can be purchased for less than 4 cents/kWh. For fleet applications, electricity could be as high as 5 cents/kWh and still produce economically competitive hydrogen.

2. Seventy-one of 154 major investor-owned utilities currently sell off-peak electricity to residential customers at retail prices less than 4.5 cents/kWh.

3. Most utilities have excess generating capacity most of the time, often exceeding 40% to 50% of their total capacity during the night and early morning hours.

4. Many utilities have marginal operating costs below 1.5-2 cents/kWh and could recover some capital costs by selling off-peak electricity at rates below 3 cents/kWh.

5. Utilities currently have sufficient excess nighttime capacity to supply electrolytic hydrogen to all FCEVs for several decades without building any new generation equipment, even if 10% of all new cars sold were fuel-cell vehicles.

5.0 Recommendations

Based on this study's positive findings, we recommend that the concept of small hydrogen electrolyzer systems for hydrogen refueling stations be extended to the next level of detail. Capital costs of the main system components need to be determined as a function of manufacturing volume, and our assumptions regarding possible off-peak electrical rates need to be firmed up with representative electric utilities.

Specifically, we recommend a two-step program to more fully explore the small-scale electrolytic hydrogen option. In the first phase of this program, the system would be designed and costed in detail and the off-peak electrical rates would be discussed in detail with one or more utilities. In the second phase, one or more prototype electrolyzer systems would be built and tested, with the goal of having such a refueling capability ready by the time prototype fuel-cell vehicles are ready for demonstration.

Specific tasks during Phase I would include:

1. Complete detailed electrolyzer design. We recommend contracting with at least two experienced electrolyzer companies to design and cost a small-scale electrolyzer system or systems to accommodate both the home market and a small, 50-car fleet market. One company would design an alkaline system and the other would design a proton exchange membrane system. One subtask should include an analysis of the costs of increasing electrolyzer output pressure to reduce the demands on the compressor.

2. Complete the specification and design of the compressor system. This task should include interaction with the electrolyzer supplier to determine the optimum combination of electrolyzer output pressure and compressor system, including the possibility of providing all compression in the electrolyzer. The compressor company or companies would be tasked to estimate the tradeoff in compressor size and cost versus the output pressure from the electrolyzer.

3. Complete the detailed specification and design of the storage system. Appropriate tanks suppliers should be tasked to design and cost storage tanks and associated fittings, valves and meters to store hydrogen at pressures up to 6,000 psi.

4. Complete detailed system design. The complete system including the electrolyzer, compressor, storage tanks, dispensing equipment, safety, and controls should be designed in detail, working with experienced companies in each area.

5. Develop mass production cost estimates. Cost estimates should be generated based on the above designs for quantities of 1, 10, 1,000, 10,000 and 100,000 systems. These mass production cost estimates for the electrolyzer should be compared and reconciled with the mass production cost estimate of $36/kW for PEM fuel cells, particularly in the case of the PEM electrolyzer. Critical cost elements should be identified and alternative materials or processes suggested to reduce costs to within acceptable levels. All capital costs should be separated into fixed costs and those costs that depend on the hydrogen production or storage level so that the economic model can be used to optimize system design as a function of hydrogen output levels.

6. Establish firm off-peak electricity rate. One or more electric utilities should be contacted to discuss in detail the conditions necessary to obtain off-peak electrical rates below 4.5¢/kWh.

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13. ABSTRACT *(Maximum 200 words)*

In this report, Direct Technologies, Inc., describes its evaluation of one approach to providing hydrogen fuel: the electrolysis of water using off-peak electricity. This approach is viewed as a short-term transition strategy for providing relatively inexpensive hydrogen before there are enough fuel-cell vehicles to justify building large natural gas reforming facilities. Other contractors at Princeton University and Oak Ridge National Laboratory are investigating the feasibility of producing hydrogen by steam reforming natural gas, probably the least expensive hydrogen infrastructure alternative for large markets. This report contains estimates of the necessary price of off-peak electricity that would make electrolytic hydrogen costs competitive with gasoline on a per-mile basis. When creating the estimates, Direct Technologies assumed that the electrolyzer systems would be manufactured in relatively high volumes compared with current production. Direct Technologies also compared this off-peak electricity price goal with actual current utility residential prices across the United States.

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