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ANALYSIS OF UTILITY HYDROGEN SYSTEMS & HYDROGEN AIRPORT GROUND SUPPORT EQUIPMENT

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Abstract

Directed Technologies, Inc. has completed three analysis projects for the hydrogen program office during the past year: a detailed mass production cost estimate for stationary proton exchange membrane (PEM) fuel cell systems, an assessment of the costs of producing electricity from stationary fuel cells for buildings with hydrogen and heat cogeneration, and a preliminary assessment of the use of hydrogen for airport ground support equipment. We conclude that the economic case for producing both hydrogen and electricity from stationary fuel cell systems is stronger than the economic case for selling only electricity to the building owner. This co-generation of hydrogen and electricity is particularly attractive for stationary fuel cell systems with greater than 50 kW of electrical capacity. The economics of small residential fuel cell systems in the 3 to 5 kW range are not promising, however, based on our current cost assessments.

Three types of airport ground support equipment were analyzed in terms of converting to hydrogen fuel cell operation: a 22-foot shuttle bus, a baggage belt loader, and a baggage tractor. We compared the likely performance and cost of hydrogen-powered ground support equipment with that of battery-powered vehicles. We conclude that hydrogen-powered vehicles could be less costly to purchase and operate with large volume production, but costs would be excessive initially. However, the number of airport ground support vehicles in the United States is too low to provide the necessary volume of sales to bring costs down. Therefore airport ground support equipment will only become cost competitive if hydrogen generation equipment and fuel cell systems are mass produced for other markets first.

Introduction

Hydrogen will most likely enter the marketplace as a fuel in conjunction with fuel cells, due to the higher efficiency of fuel cell systems compared to internal combustion engines. In previous years we have compared the performance and cost of passenger vehicles powered by fuel cells with the cost and performance of conventional gasoline-powered vehicles as well as hybrid electric vehicles (Thomas 1997a, 1997b, 1998b, 1998c, 1998e, 1998f, 1999a). We have shown that hydrogen onboard storage is possible and cost-effective today with 5,000 psi carbon-fiber wrapped composite tanks (James 1996, 1997b, 1999a). We have shown that hydrogen could be produced and sold at a cost that would be competitive with gasoline per mile driven in a conventional vehicle, as long as that hydrogen was used in a fuel cell vehicle (Thomas 1997c, 1998e, 1999b).

This year we have moved from the analysis of hydrogen-powered passenger vehicles to evaluate the efficacy of hydrogen in the stationary utility fuel cell business and in airport ground support equipment. We first summarize the results of the two stationary fuel cell projects, and then describe the results of our analysis of airport ground support equipment powered by hydrogen.

The following sections describe the economic analysis of a total building fuel cell system, including the necessary steam methane reformer to produce hydrogen on-site, the fuel cell system itself including all necessary ancillary equipment, plus a DC to AC inverter and required power equipment to permit hook-up to the power grid at the local building. We have combined the two DTI tasks (high volume manufacturing cost estimation for the fuel cell system only and the more general building economic assessment) in the following sections. For a more detailed report on the mass production cost estimates for stationary PEM fuel cell systems, see (James 1999b).

DTI also published a draft interim report on stationary fuel cell systems with hydrogen cogeneration in May of 1998 (Thomas 1998d), based on fuel cell system costs extrapolated from earlier DTI mass production fuel cell costs for passenger vehicles (Lomax 1997 and James 1997a). For this earlier cost estimate, we made simplifying assumptions to project stationary fuel cell costs based on the vehicle fuel cell estimates such as increased catalyst loading, reduced current density, and thicker membranes for stationary fuel cell systems compared to vehicle fuel cell systems. This current report is, however, considered more accurate, since we conducted a bottom-up mass production cost assessment, utilizing manufacturing techniques and fuel cell design that are more appropriate for the stationary fuel cell systems that must operate at least ten times longer than vehicle fuel cell systems. While much of the background information from the earlier building fuel cell system analysis is repeated here, the actual fuel cell costs estimates in this report take precedence over the earlier report. In general the economics are slightly worse now than we predicted in May of 1998. While the projected fuel cell stack costs are lower, we have added a 6%/year fuel cell stack degradation factor and we also added a 90% hydrogen system capacity factor in addition to an assumed 95% plant availability factor.

Executive Summary for Stationary Fuel Cell Systems

The ONSI Division of International Fuel Cells has sold over 150 of their PC-25 200-kW phosphoric acid fuel cell systems for stationary power. Several companies are now developing stationary proton exchange membrane (PEM) fuel cell systems to generate electricity onsite from natural gas for small buildings or even individual residences. These fuel cell systems include a fuel processor such as a steam methane reformer and gas cleanup system to provide hydrogen to the fuel cell. According to our economic assessment, however, cost reductions will be required for these stationary fuel cell systems to compete economically with utility supplied electricity in most parts of the United States. The economics can be improved to some degree by supplying part of the heating load for the building, but this requires a good match between electrical and thermal loads which are not often coincident in time both over 24 hours and over a full heating/cooling season, particularly for a residence. Stationary fuel cells may serve other purposes such as very clean, quiet and reliable backup power, and government agencies may underwrite early deployments to promote the development and use of clean fuel cell technology, but widespread use will probably require better economic performance.

The main purpose of this analysis is to consider a second co-product for the stationary fuel cell system: hydrogen for use either in a fleet of fuel cell vehicles (FCV) or for other industrial purposes. The steam methane reformer could either be oversized to provide extra hydrogen for the vehicle, or the reformer could be operated at night when electricity demand is small, essentially improving the capacity factor for the reformer system by generating and storing a high value product (hydrogen) when electricity demand is minimal and therefore of low value.

Constructing an oversize reformer to supply hydrogen for FCVs might be cost effective if the fuel cell system were operated at high capacity factor to produce electricity. However, the electrical capacity factor for most buildings rarely exceed 50%, and most residences have capacity factors in the range of 30% -- the average power draw is only one third of the peak fuel cell capacity. Therefore the fuel cell system has 50% to 70% excess electrical capacity that cannot be used on site. The economics of the stationary fuel cell system supplying only electricity is not promising with these low capacity factors. In California, for example, we project a -10% return on investment for a 50-kW stationary fuel cell system even if 10,000 such systems are produced -- the project loses money compared to simply buying electricity from the grid at prevailing *average* commercial electricity rates in California.

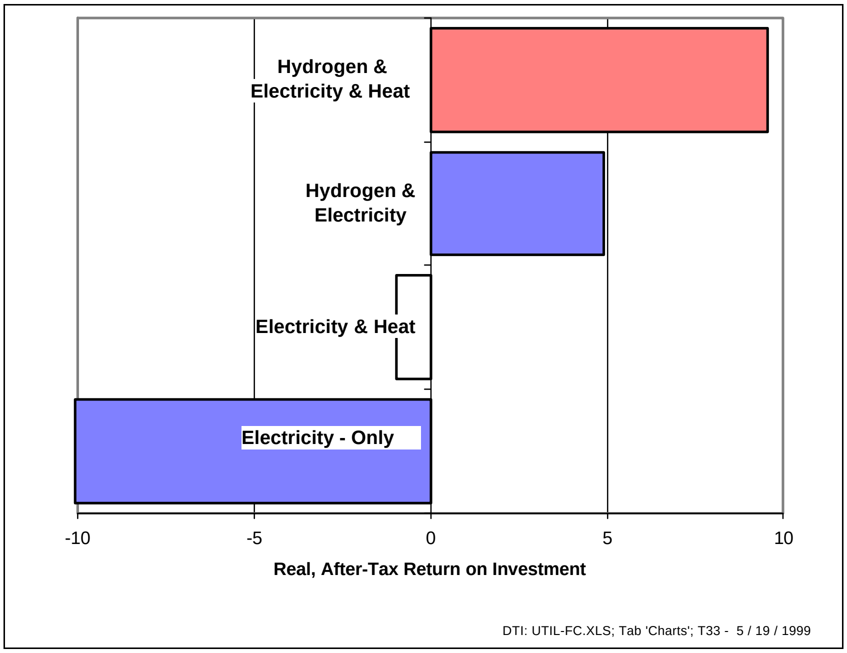
These economics might be improved with electric utility transmission and distribution credits -- a utility could avoid adding new transmission and/or distribution equipment in certain regions by adding stationary distributed power generation such as fuel cell systems at its customer's facilities. We have not considered these credits in this analysis. Rather, we have analyzed the economics for the building owner -- can the owner reduce total utility costs by generating electricity on-site instead of purchasing electricity from the local utility?

One option to improve system economics would be to sell electricity back to the grid during off-peak hours. However, the utility system has very little need for excess capacity when the homes and buildings have low demand. After all, the low demand for off-peak electricity is as a result of the aggregated demands of buildings, homes and industry, most of which are low at night. The low price of off-peak electricity does not improve the system economic outlook.

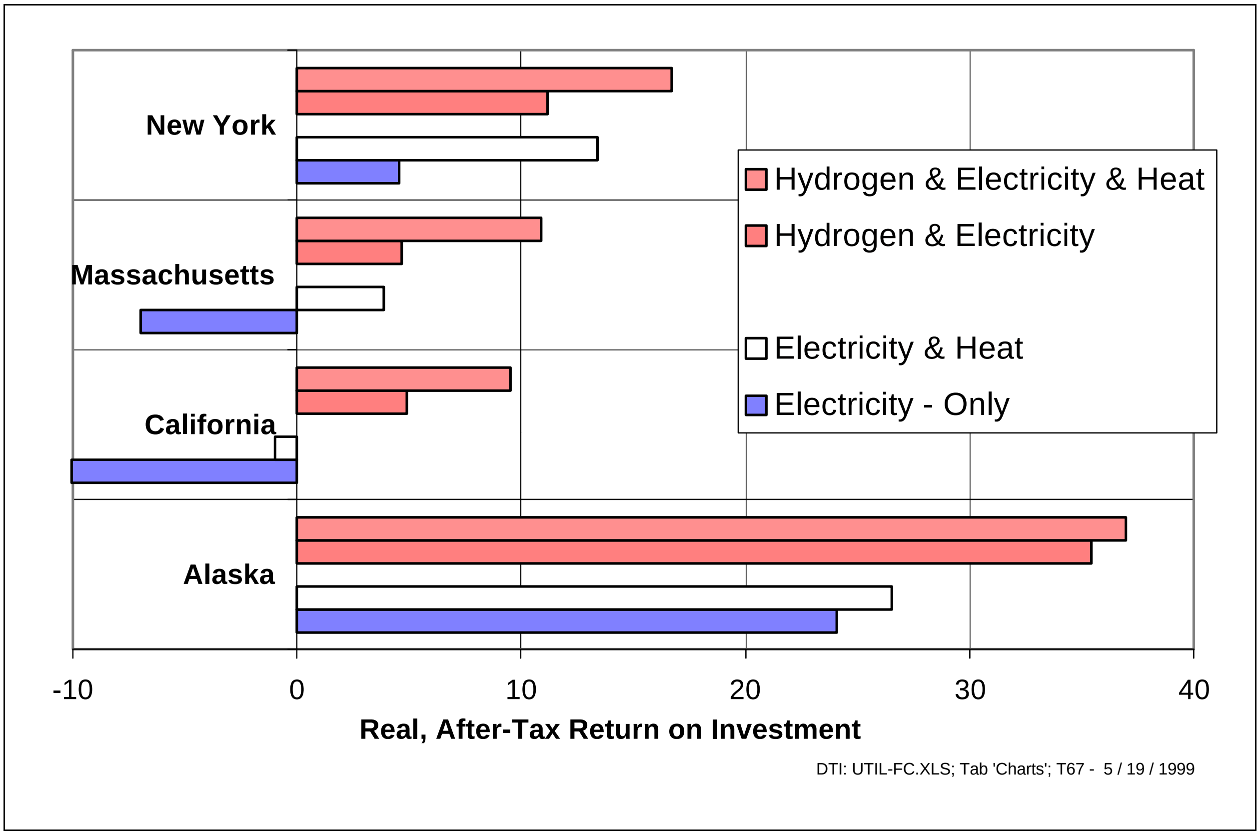
The economics can be improved by supplying some of the waste heat from the fuel cell to the building for space heating or for hot water. For a hospital or hotel, we are projecting that the -10% return for supplying only electricity can be improved to a positive return of 1.5% (Northern climate) to -1.0% (Southern climate).

The stationary fuel cell economics are further improved by making hydrogen during the off-peak electrical demand periods. The steam methane reformer is operated at nearly full capacity day and night. Hydrogen is diverted to the fuel cell to meet the onsite electricity demand. All hydrogen not used by the stationary fuel cell system is diverted to a compressor and storage system. This excess hydrogen is either stored in stationary compressed gas tanks for later fast-fill delivery to the FCVs on demand, or the hydrogen is pumped directly into the FCV tanks -- the slow-fill option. Alternately, the hydrogen could be stored for later industrial use on-site.

In this case the project economics are improved significantly, as shown in Figure 0. Selling both hydrogen and electricity increases the expected ROI from -10% to almost 5%. Adding thermal cogeneration further increases returns to 9.5 % for a southern climate such as California, approaching our target goal of 10% real, after-tax return on investment.



These results are very dependent on the local prices for natural gas (the system feedstock) and electricity (providing the main avoided cost for the project.) The ideal location would have very low natural gas prices and very high electricity prices. Alaska has such a favorable ratio, with electricity to natural gas price ratios about twice the national average. As shown in Figure 1, Alaska would have favorable returns supplying just electricity. By adding hydrogen, however, the returns are increased to above 35% assuming the costs developed in this report for fuel cell systems at the 10,000 production quantity level. Massachusetts is very similar to California, while New York has more favorable conditions since the average commercial electricity rates are higher (11.5 cents/kWh vs. 9.4 cents/kWh for Massachusetts in 1998.)

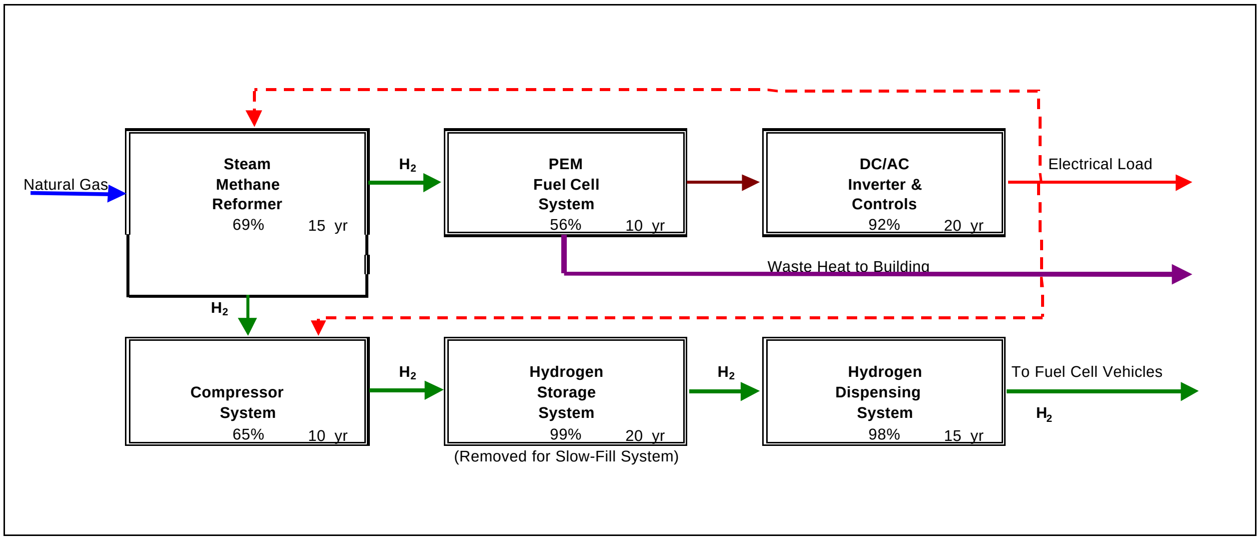


While the 50-kW commercial building looks promising for hydrogen coproduction from a stationary fuel cell system, the economics of a residential system are far less favorable. Even at 10,000 quantity production, for example, we estimate that electricity would have to sell at 44 cents/kWh in California before a 3.4-kW home fuel cell system would be profitable. Conversely, the estimated capital cost of a 3.4-kW system in quantities of 10,000 ($3,300/kW) would have to be reduced to between $220/kW (California) and $650/kW (Alaska) to reach our target of 10% real, after-tax rate of return for electricity displacement only, or to between $525/kW and $1,140/kW including hydrogen coproduction. In other words, adding hydrogen coproduction allows higher cost fuel cell systems to be economic.

We conclude that hydrogen will be most beneficial in 50-kW or larger commercial building fuel cell systems, with the potential to significantly improve project economics. Based on current cost projections for 10,000 quantity production of residential fuel cell systems, significant cost reduction would be required to make either the stand alone fuel cell system or the hydrogen cogeneration system economic.

Stationary Fuel Cell System Description

The cogeneration of hydrogen from stationary fuel cells to supply fuel cell vehicles or other industrial applications looks promising, particularly since the electrical capacity factor for homes and buildings is rarely over 50%. The stationary fuel cell system is under-utilized without co-products such as heat and hydrogen. The general system block diagram of the building fuel cell system is shown in Figure 1, including the assumed efficiencies (LHV) and lifetimes of the components. The input fuel is natural gas, and the system supplies electricity and heat to the building, and it can produce hydrogen for fuel cell vehicles or for other industrial uses.



We begin with a description of typical thermal and electrical loads for small buildings, followed by a discussion of utility pricing, fuel cell system costs, and finally a description of the fuel cell system economics.

Building Electricity and Heating Loads

Typical Electrical Loads

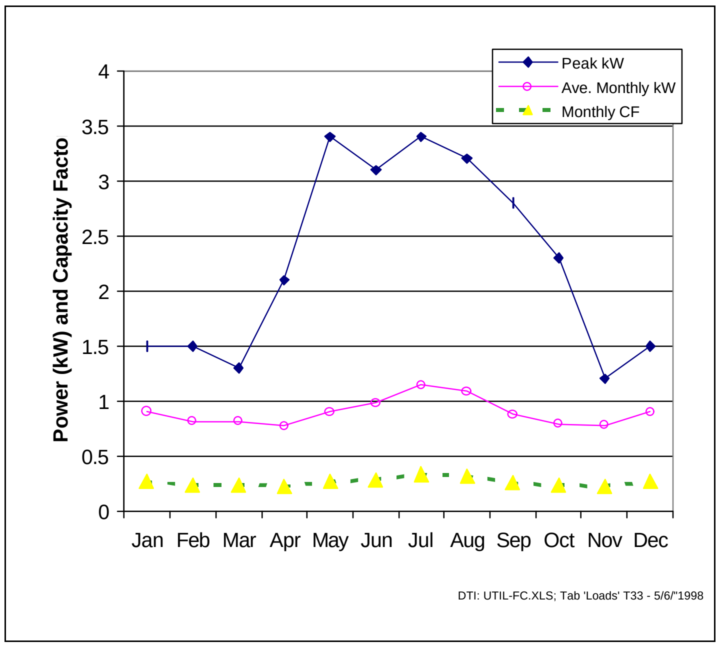
Most buildings such as shopping malls, offices, schools and residences consume most of their electricity during the day. A typical residence might require a peak power of 3 kW on a hot August afternoon, but the average electrical consumption over a year might only be 900 watts or less. Other buildings such as hospitals and hotels may have greater night-time loads, but daytime consumption is still much greater, often by a factor of two. Any fuel cell sized to provide the peak afternoon electrical load in August will be under-utilized during a January night.

The average annual electrical capacity factors[1] for these buildings vary from as low as 17% for a junior high school to at most 63% for a medium hotel as estimated by Arthur D. Little (1995) and summarized in Table 1.

[1]Capacity factor is defined as the average building electrical energy consumption in kWh over "T" hours divided by the peak production capacity of the fuel cell system in kW times "T."

Table 1. Electrical Annual Average Capacity Factors for Typical Buildings

	Peak Electrical Power (kW)	Average Electrical Power (kW)	Annual Electricity Capacity Factor
Private Residence - North	3.4	0.9	0.24
Private Residence - South	3.7	1.07	0.27
Junior High School	520	90	0.17
Medium Office Building	300	112	0.38
Retail Store	1,000	370	0.38
Medium Hotel	420	254	0.63
Hospital	2,400	1,320	0.57



The electrical capacity factor also varies seasonally. In the winter months, the effective monthly capacity factors will be less than the averages shown in Table 1. The average monthly power and peak power levels for residential buildings are shown in Figure 0, also from the ADL study (1995).[2] In the winter months, a fuel cell sized for the 3.4 kW peak summer load would only be utilized at 22 to 24% of its rated capacity for onsite electricity.

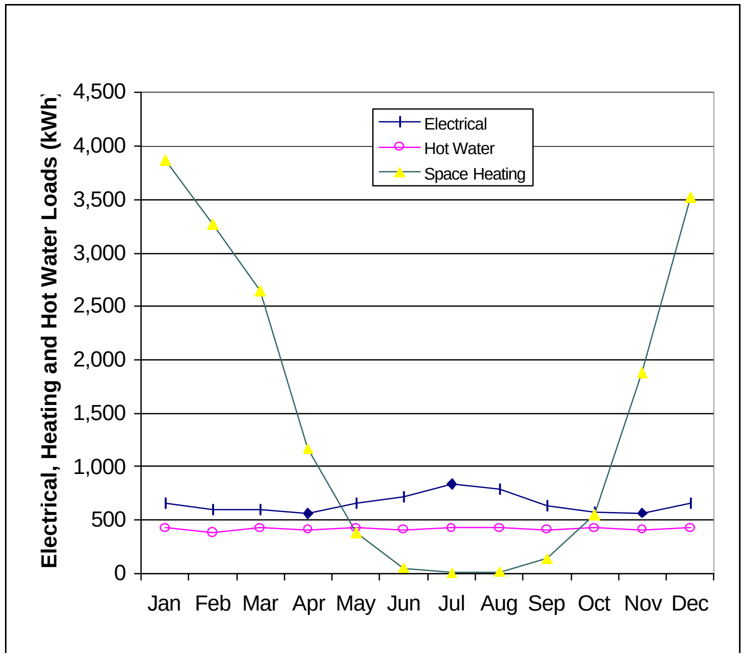
Finally, on an hourly basis the load factors become even worse. A typical home might draw at most 200 to 300 watts during the hours from midnight to 5 or 6:00 AM, or an hourly capacity factor of only 6% to 9% for a 3.4 kW fuel cell system.

Typical Heating Loads

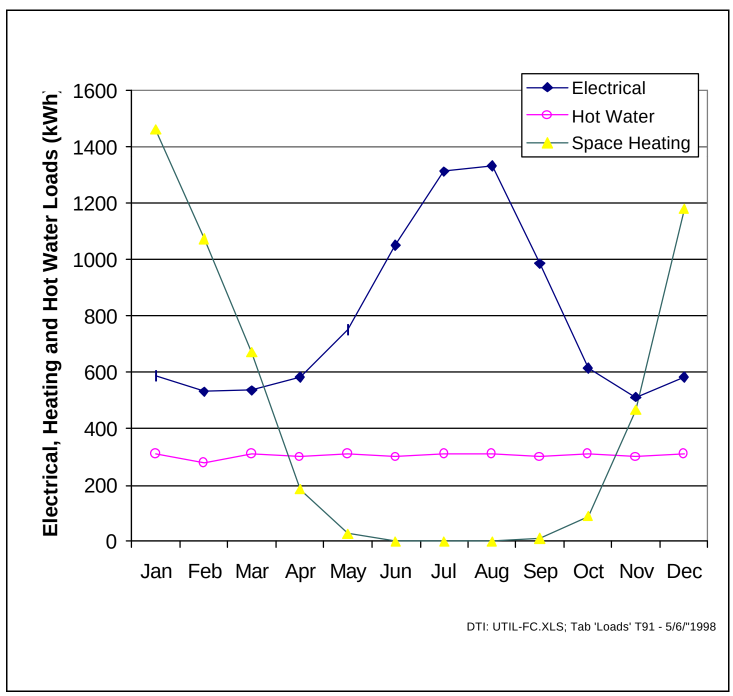
Heating loads include primarily hot water and space heating requirements. Hot water loads tend to be uniform geographically and over time, while heating loads vary widely both geographically and seasonally. Figure 1 shows the same (northern) residence as the previous figure, with the average monthly heating and

[2] Ibid., Table A.8.1

hot water loads added. There is a reasonably good match between the electrical and water heating loads. A fuel cell with approximately 50% efficiency would produce enough heat to cover the hot water requirements, although the efficiency of heat exchangers would be low at the low exit temperature of PEM fuel cells at 80 °C, which is not much higher than the water leaving a typical hot water heater at 50 °C to 60 °C. The space heating requirements are much greater than the electrical loads in the winter months, so cogeneration would not impact space heating requirements significantly for a residence.



The situation is somewhat different in southern climates of the US, as illustrated in Figure 0. Heat from the fuel cell electrical generation could supply most of the hot water needs, as with the northern house, but the waste fuel cell heat might also supply some small fraction of the space heating requirements, assuming heat transfer efficiency of greater than 70%.



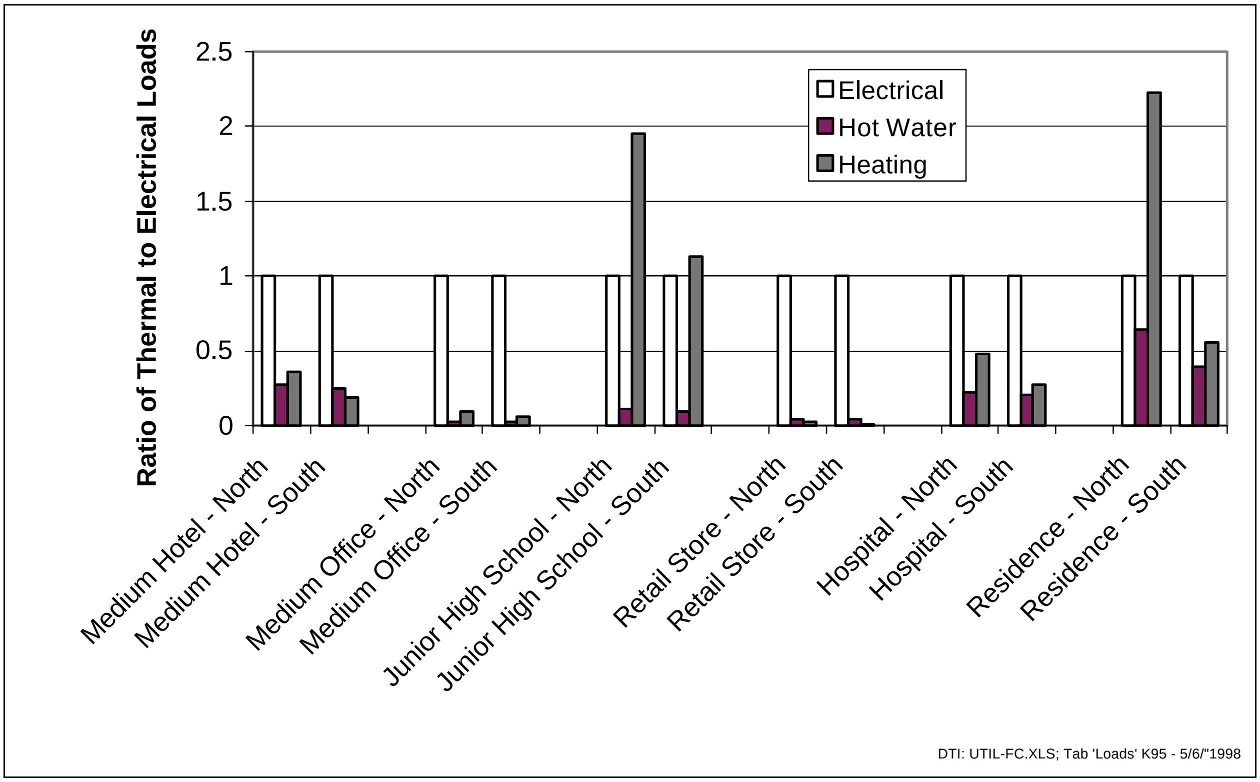
On an hourly basis, the hot water loads are also well matched to the electrical loads -- in general both peak during the day. However, the space heating loads occur primarily at night, when the fuel cell output is at a minimum, typically less than 10% of the peak capacity. Thus it is unlikely that fuel cell excess heat can contribute much to the space heating requirements of a private residence.

Typical residential hot water and space heating loads are summarized in Table 2, compared to the total annual electrical loads.

The ratios of electrical to thermal loads for the various buildings are summarized in Figure 1, also

Table 2. Typical Residential Annual Thermal and Electrical Energy Requirements (kWh)

	Space Heating	Hot Water	Electrical
Northern Residence	17,500	5,040	7,870
Southern Residence	5,160	3,650	9,360

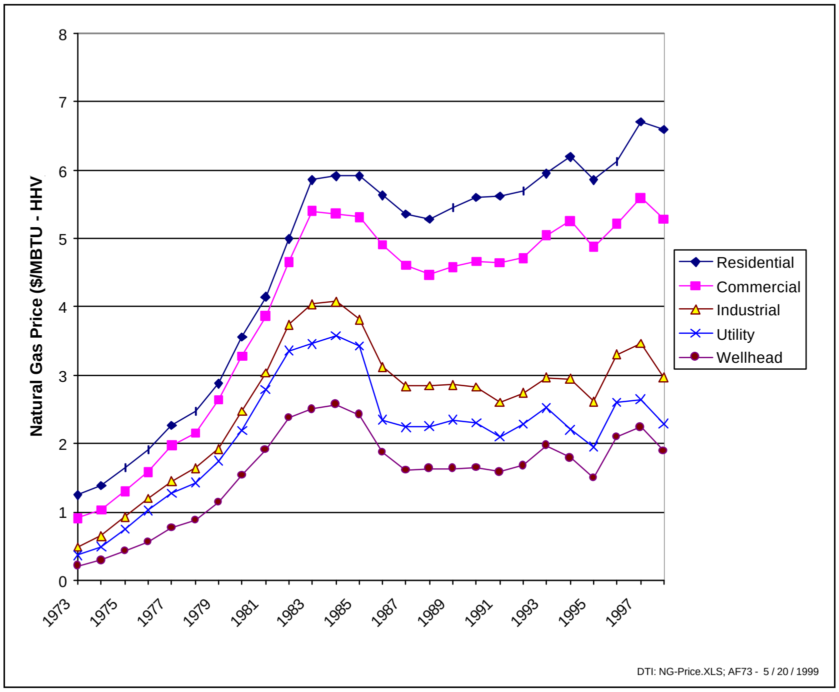


from the ADL report. The residential building is unique with respect to the match between electrical and hot water loads. All other buildings analyzed by ADL have much lower hot water demands compared to the electrical requirements. The total heating load (space and water) for offices and retail stores is less than 10% of the electrical load, indicating that thermal cogeneration will not provide significant advantages for these buildings. Hospitals and hotels are better, with combined space and water heating loads 70% of electricity in the north and approaching 50% in the south.

In summary, thermal cogeneration at a stationary PEM fuel cell site does not appear to offer significant advantage for office buildings and retail stores, but may be beneficial for hotels, hospitals and private homes. In general space heating is not a good temporal match to the fuel cell electrical output, but water heating does match the electrical load reasonably well. The low temperature of existing PEM fuel cells (80°C) further limits heat transfer efficiency for reasonably sized heat exchangers, either to a building heat load or even to the atmosphere. The Department of Energy is planning to fund research into PEM fuel cells that can operate above 100°C, primarily to help reduce the poisoning effects of carbon monoxide from fuel processors. If these higher temperatures are achieved, thermal cogeneration will be more beneficial.

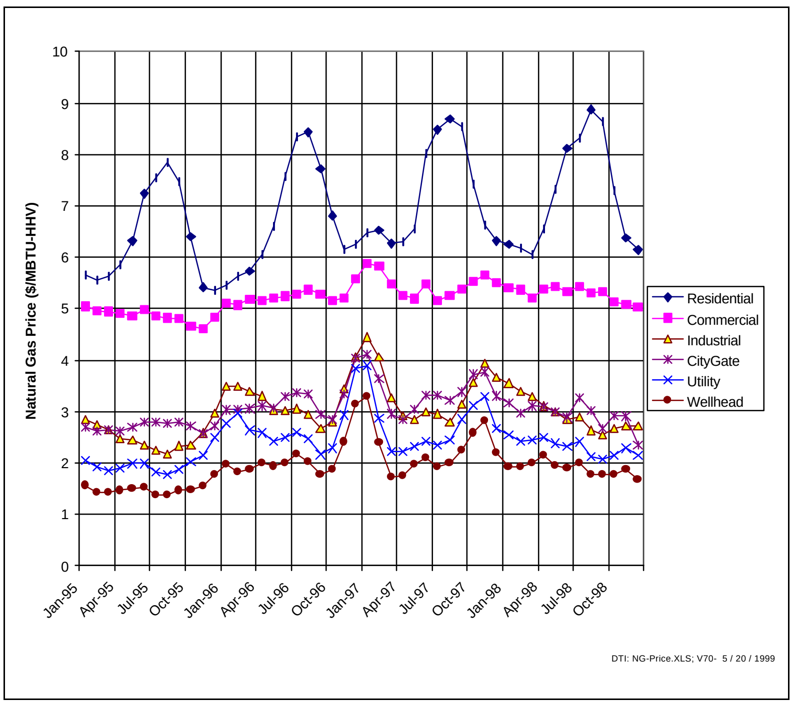
Gas and Electric Utility Prices

The financial viability of stationary fuel cells will depend to a large degree on the prices of electricity and natural gas at the building. The expected electric utility prices will determine the cost savings by installing a building fuel cell system, and the expected utility electrical rates and regulations will also determine if it is ever viable to consider selling power back to the grid during off-peak periods.



Natural Gas Prices

Natural gas prices have stabilized in current dollars since the early 1980's, which means prices are falling in constant (inflation-adjusted) dollars. Natural gas costs about the same today in constant dollars as in 1973. Average prices rose slightly since 1995 but dropped again in 1998 as shown in Figure 0.



Natural gas prices have averaged around $2/MBTU (higher heating value basis) at the wellhead over the last few years, with average U.S. utility gas prices in the range of $2.10 to $3/MBTU, as shown in Figure 1, with industrial gas prices typically $0.5/MBTU higher than utility prices. For commercial buildings, however, the delivered price of natural gas averages around $5.50/MBTU, and residential gas prices fluctuate seasonally, in the $6/MBTU range in the winter, rising to as much as $8/MBTU in the summer. The economics of distributed fuel cell power generation will depend greatly on whether the fuel cell system owner can obtain natural gas at industrial or utility rates compared to commercial or even residential rates. Presumably a building owner would have to pay commercial rates for natural gas, making the fuel cell option much less attractive than a company that could negotiate industrial rates for the natural gas fuel. But if a utility or independent power generator could obtain utility natural gas rates by bundling a large number of distributed fuel cell systems, then fuel cells running on natural gas as the feedstock would be much more economical.

Natural gas prices also fluctuate geographically, typically lower in regions with indigenous natural gas supplies, and higher elsewhere. For example, average state residential rates varied from a low of $3.65/MBTU (HHV) in Alaska to a high of $20.98/MBTU in Hawaii in 1997. The range is less in the contiguous 48 states, varying from $4.13/MBTU in Wyoming to a high of $9.28/MBTU in Rhode Island for 1997.

For the purposes of this analysis, we are most interested in those states that will most likely have fuel cell vehicles. Assuming that the California zero emission vehicle (ZEV) mandate provides the early impetus for introduction of FCVs, then California and the northeastern states that have currently indicated they will opt into the ZEV program (New York and Massachusetts) are the leading candidates. Recent natural gas rates for these three states are summarized in Table 3 along with those in Alaska, with the least costly natural gas. Unfortunately, the northeastern states have rather high natural gas prices, although California prices are near the national average.

Table 3. Average Annual Natural Gas Prices for Selected States (1997/1998) ($/MBTU - HHV)

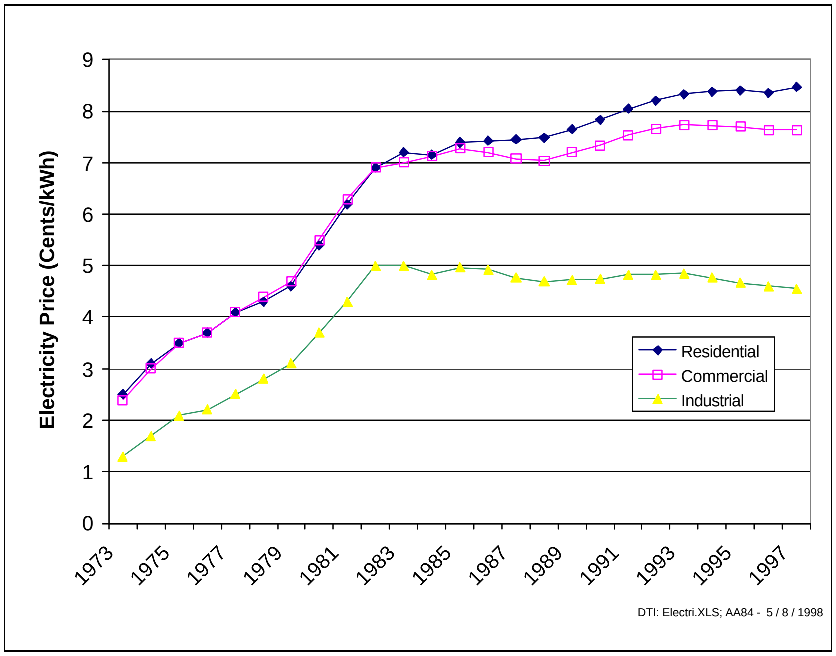
	California	New York	Massachusetts	Alaska
Residential	6.55 / 6.93	8.60 / NA	8.58 / NA	3.65 / 3.67
Commercial	6.21 / 6.26	6.64 / NA	6.51 / 6.62	2.37 / 2.41
Industrial	3.89 / 3.59	4.87 / NA	5.19 / 5.45	1.49 / NA
Utility	2.98 / 2.79	2.76 / 2.56	2.9 / 2.78	1.67 / 1.80

Electricity Prices

Electricity rates tend to be more variable than natural gas prices, fluctuating not only regionally but also from one utility to another, with each utility offering a wide range of rate structures for residential and particularly commercial and industrial customers. As shown in Figure 2, the average U.S. electricity prices have stabilized in current dollars at about 4.5 cent/kWh for industry, 7.6 cents/kWh for commercial buildings and 8.5 cents/kWh for residences. In constant (inflation-adjusted) dollars, electricity costs no more today than in 1973.

Seasonal variations in electricity prices are less than those for natural gas, as shown in Figure 2. Average residential rates vary between 8 cents/kWh in the winter and 9 cents/kWh in the summer.

Hawaii has the highest average electrical rates, averaging 15.0 cents/kWh for 1997 for private homes, with New England not far behind at an average of 11.8 cents/kWh. New York has the second highest average residential rates at 13.8 cents/kWh for 1997. Idaho and Washington have the lowest residential rates for 1997 at 5.0 and 5.2 cents/kWh. The 1997 and 1998 average rates are listed in Table 4 for the four states of interest. In all cases these rates are the total revenues (including energy charges and power charges) divided by the energy consumed in kWh (EIA 1999).



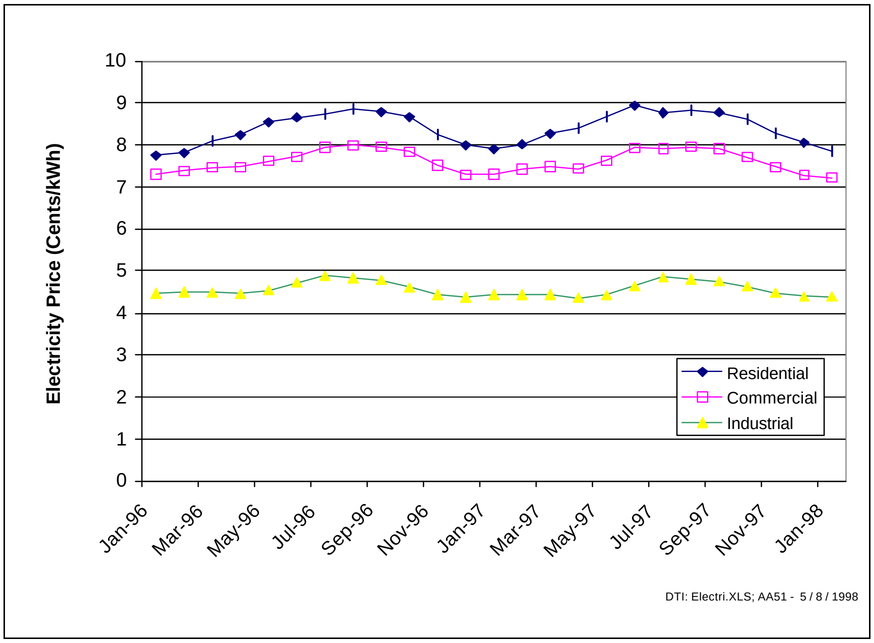
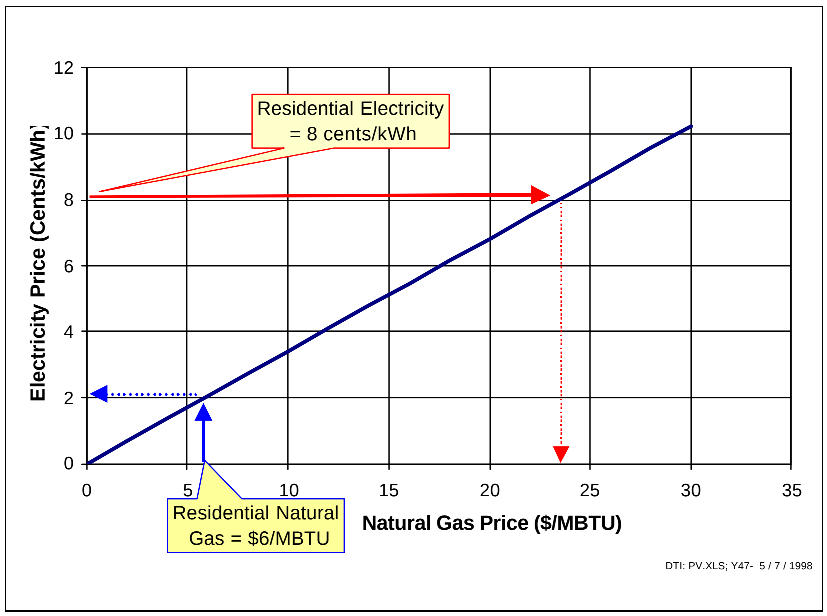


Table 4. Average Electrical Revenue per Kilowatthour for 1997/1998 (cents/kWh)

	California	New York	Massachusetts	Alaska
Residential	11.2 / 10.9	13.8 / 13.9	11.2 / 10.6	10.9 / 11.3
Commercial	8.8 / 8.8	11.4 / 11.5	9.3 / 9.4	9.3 / 9.3
Industrial	5.9 / 5.9	5.3 / 5.0	8.4 / 8.4	8.3 / 7.8

Comparison of Natural Gas and Electrical Rates



Natural gas is the least expensive fuel delivered to an end user on an energy equivalent basis. On a BTU basis, residential electricity selling at 8 cents/kWh is equivalent to natural gas at $23.46/MBTU, or almost four times more expensive as residential natural gas selling at $6/MBTU, as shown in Figure 1. Conversely, electricity would have to sell at 2 cents/kWh to provide the same energy as natural gas at $6/MBTU. Therefore electricity generated on-site from a natural gas-powered fuel cell with natural gas selling at $6/MBTU and 50% fuel cell efficiency and 65% steam reformer efficiency would have to sell the resulting electricity at 6.2 **4**/kWh just to recover fuel costs. If the capital recovery costs for the natural gas reformer and fuel cell system are less than the difference between the current cost of electricity and 6.2 **4**/kWh, then the project would be economic.[3]

Selling electricity back to the utility does not look promising from this perspective. Since off-peak electricity prices are generally less than 4 cents/kWh, the fuel cell owner would most likely not be able to sell off-peak power back to the grid at 6.2 **4**/kWh, even if the fuel cell system were free.

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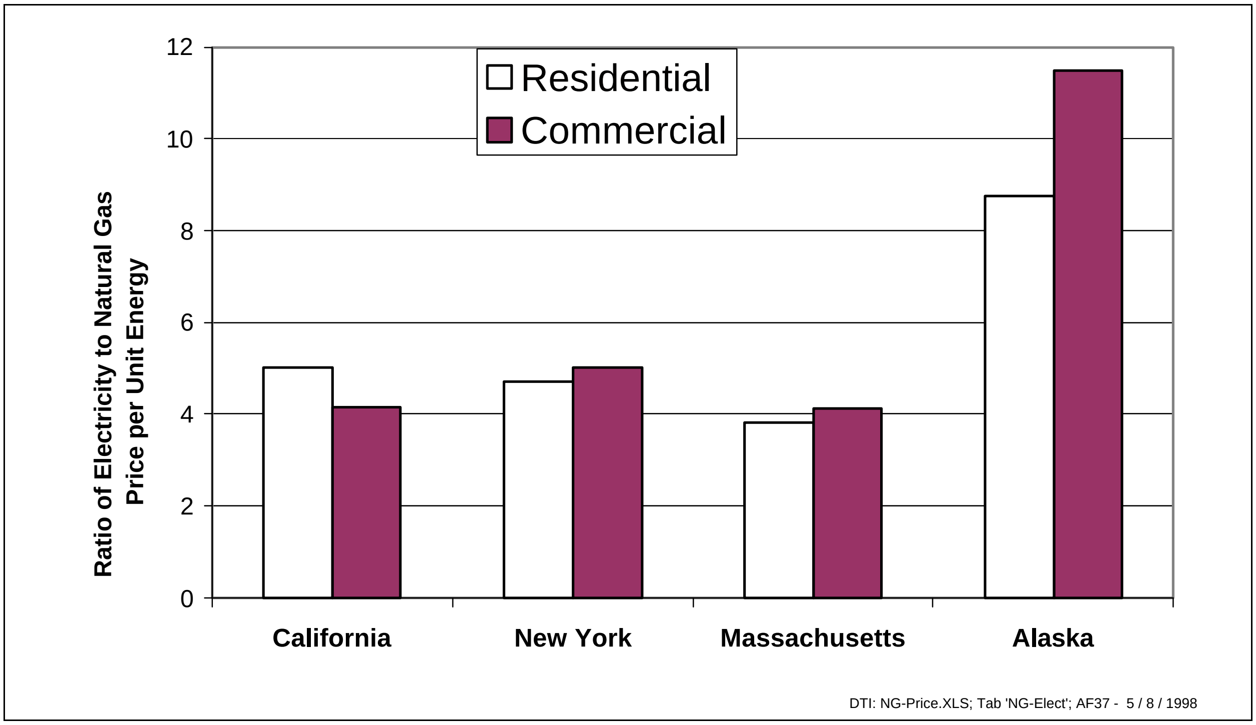
[3]The actual electricity charge just to recover natural gas fuel cost would be 7.5 **4**/kWh for natural gas at $6/MBTU, taking into account the electricity needed to run the reformer (1.64 kWh per kg of hydrogen produced), the fuel cell efficiency (53.2%), the steam reformer efficiency (68.6%-LHV) and the inverter efficiency (92%).

The most likely geographical region for stationary fuel cell penetration should have a high ratio of electricity to natural gas costs. Alaska has the most favorable ratios as shown in Figure 2, with electricity prices per unit energy 8 to 11 times greater than natural gas prices per unit energy. The primary ZEV states all have ratios near four to one, similar to the national average.



Stationary Fuel Cell System Mass Production Cost Estimates

We have estimated the cost of the fuel cell system using the DTI cost database built up over the last several years under DOE and Ford Motor Company contracts. Most of the costs are based on a detailed "bottom-up" analysis of the individual system components, using commercial cost estimation software for large scale mass production materials, manufacturing processes and assembly time and cost.

Fuel Cell System Cost Estimates

DTI, working with Ford Motor Company costing department, has previously analyzed the cost of mass-produced PEM fuel systems for passenger vehicles (Lomax 1997). These cost estimates are not valid for stationary systems, however, due to very different operating conditions. The stationary fuel cell would normally operate at nearly constant output near its rated capacity for much of the day, with decreased output at night. Operating lifetimes of greater than 50,000 hours (five years) are desirable for a stationary fuel cell system. By contrast, an automotive fuel cell generally operates for at most a few hours per day, and rarely operates at the design peak power for more than 10 to 20 seconds two or three times per day. The average vehicle power draw on typical driving cycles is often only 10% of the rated fuel cell capacity. Lifetimes of 5,000 hours would be adequate for the life of the car. As a result the stationary fuel cell must be more robust.

In addition, the fuel cell production volume for a passenger vehicle would most likely be much larger than the production quantity for supplying distributed power to buildings. A major vehicle production line turns out 300,000 vehicles per year. A fuel cell vehicle power train would have 50 to 80 kW peak power capability. For comparison, there are estimated to be on the order of 2.2 million buildings in the U.S. including office buildings, hospitals, hotels and retail stores (A.D. Little 1995). The average electrical load for these buildings varies from 33 kW for hotels and stores up to 95 kW average power draw for office buildings. With capacity factors near 50%, the peak power would vary between 66 kW and 200 kW, or at most three times the fuel cell peak power required for one passenger vehicle. Therefore to reach a fuel cell power production level equal to that for 300,000 vehicles per year, industry would have to install fuel cell systems for on the order of 150,000 buildings per year, or 7% of the estimated pool of likely buildings[4].

Given the widely dispersed and highly variable type of building in terms of size, load factors, ownership, etc., it is highly unlikely that this penetration level would be achieved for many years, whereas one automobile manufacturer could conceivably build up this volume of fuel cell demand within a few years. We have therefore assumed a much slower ramp-up of stationary fuel cell system sales. In particular, we have assumed that the fuel cell manufacturer could not afford to install the large scale mass production equipment that would be built to support the automotive market. For example, instead of building a roll-to-roll machine to manufacture the membrane electrode assemblies (MEAs), the heart of the fuel cell system, we assume here that lower production volume batch machines are built to support the distributed utility market. At one extreme, fuel cell manufacturers would purchase MEAs from existing low-volume suppliers at costs on the order of $500 per square meter. These MEAs are made in a batch mode, with little or no automation. We then considered various levels of automation as sales volumes increased, assuming sales of 100, 1,000, 10,000 30,000 and 60,000 50-kW stationary fuel cell systems per year.

The cost of any fuel cell system will also depend on output power requirements. Some analysts quote prices in $/kW of peak power and apply this cost metric to all sizes of fuel cells. However, some components in any system do not scale linearly with output power. This is particularly true for some ancillary components such as switches, valves, sensors, safety devices, enclosures, etc., as well as some stack components such as tie rods and end plates. We have therefore estimated the fuel cell system cost as a function of membrane area, which can be converted to the cost as a function of output power. For this analysis, we are particularly interested in a range of output power levels from 3 kW peak for a typical residence up to the 50 to 200 kW range for a typical building.

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[4]This comparison assumes that the building fuel cell has approximately the same power density as the automotive fuel cell. Originally we assumed that the stationary fuel cell system would operate at much lower power density to prolong lifetime. For example, if the stationary fuel cell operated at one quarter the power density of the vehicle fuel cell, then each kW of stationary power would require four times the fuel cell membrane area compared to a vehicle fuel cell. However, we now are assuming that stationary fuel cell systems will have similar peak power density, but higher platinum loading and thicker membranes to assure long life.

We have also assumed near ambient pressure operation of the stationary fuel cell system, replacing an expensive compressor that provides three atmospheres of air pressure to the vehicle fuel cell cathode with a blower for the stationary system. This reduces the parasitic power required to run the fuel cell system, and also reduces the ancillary costs for the system.

The estimated cost of the fuel cell stack (excluding ancillary components) can be represented by the following equation (see James 1999b for details on all fuel cell cost derivations):

$$C_s = M \ x \left[\left(\frac{(A - 105.4)}{10} + \frac{17.56 \ x \ L_p \ x \ C_p}{380} \right) x \ \frac{P_G \ x (1 + d \ )^N}{P_d} + B \right]$$

where M = a fixed cost markup (1.1 default),
A = a cost parameter that depends on production volume (see table below),
L_p = the fuel cell platinum loading for both electrodes (mg/cm^2),
C_p = the cost of platinum (\$/troy ounce),
P_G = the fuel cell gross DC peak power (kW),
P_d = the fuel cell power density (W/cm^2),
d = the annual fuel cell degradation (%/year),
N = the planned fuel cell lifetime (years), and
B = a second cost parameter.

The fuel cell stack cost depends on the two cost parameters (A,B) which in turn have been developed for five different production volumes as summarized in Table 5. The "A" parameter is the power-dependent term (specified in terms of $ per square meter of membrane area), and the "B" parameter is the fixed cost for the fuel cell stack.

Table 5. Fuel Cell Stack Cost Parameters

Production Volume	Cost Parameter "A" ($\$/m^2$)	Cost Parameter "B" ($)
100 units	811.77	1311.3
1,000	722.54	363.33
10,000	454.45	428.51
30,000	329.24	405.79
60,000	312.26	160.98

The fuel cell stack cost assumes that the membrane degrades a fixed percentage each year, primarily as a result of catalyst degradation. For this analysis, we assume a six percent per year drop, based on a review of several laboratory degradation experiments (James 1999b).

The cost given by Equation 1 is for the fuel cell stack. A complete fuel cell system includes several other ancillary components as listed in Table 6. Again, we have estimated these ancillary component costs as a function of the fuel cell output power and also the production volume. We show the results for production volumes of 100 units and 10,000 units in Table 6. The resulting cost for these

Table 6. Fuel Cell Ancillary Component Cost Estimates (US$)

	Production Quantity	Fuel Cell Gross DC Power (kW)				
		4	10	50	100	200
Air Blower	100	$208	$292	$774	$1,169	$1,276
	10,000	$197	$277	$733	$1,108	$1,209
Humidification	100	$110	$111	$115	$120	$130
	10,000	$110	$110	$110	$110	$117
Radiator	100	$215	$266	$606	$1,030	$1,878
	10,000	$181	$224	$510	$867	$1,581
Stainless Steel Pump	100	$384	$393	$452	$527	$677
	10,000	$323	$331	$381	$444	$570
Iron Pump	100	$50	$56	$136	$235	$435
	10,000	$50	$53	$128	$222	$411
Control Electronics	100	$53	$58	$88	$125	$200
	10,000	$50	$50	$70	$100	$160
Actuation & misc.	100	$2,280	$2,345	$2,782	$3,328	$4,420
	10,000	$2,052	$2,111	$2,504	$2,995	$3,978
Piping, Valves, etc.	100	$206	$215	$275	$350	$500
	10,000	$165	$172	$220	$280	$400
Totals	100	$3,506	$3,736	$5,228	$6,884	$9,516
	10,000	$3,128	$3,328	$4,656	$6,126	$8,426

ancillary components can be approximated by a quadratic equation in fuel cell output power -- the cost does not vary linearly with power. For 100 production units, the estimate ancillary cost is given by:

$$C_a = 3{,}343.5 + 39.942 x P_G - 0.0454 x P_G^2$$

For 10,000 production quantity, the ancillary costs are:

$$C_a = 2{,}980.2 + 35.654 x P_G - 0.0422 x P_G^2$$

The results of this stationary PEM fuel cell cost analysis are compared with our earlier cost projections for PEM vehicle fuel cell systems in Table 7 for 50 kW systems. The 50-kW stationary fuel cell system cost is projected at $490/kW for 100 units, decreasing to $310/kW for 10,000 units, while the mobile fuel cell system cost is estimated at $36/kW in automotive production volumes.

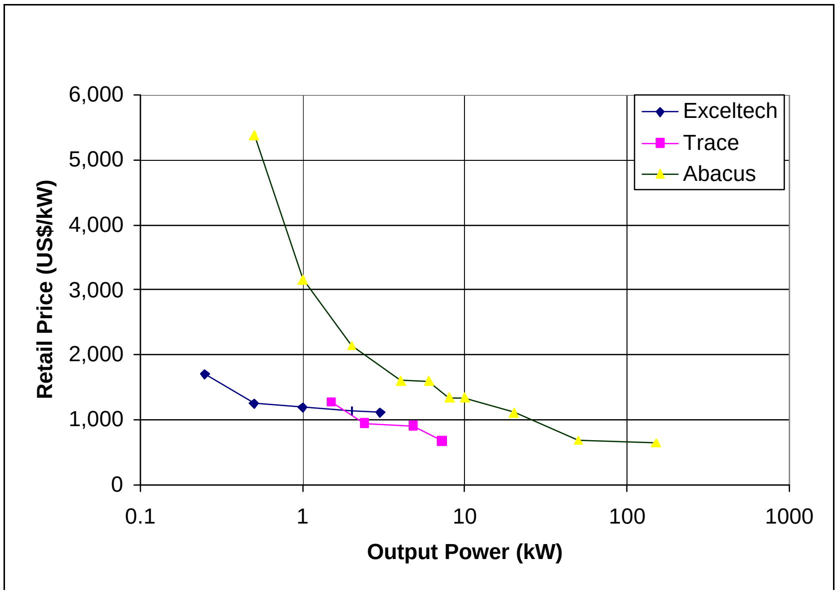
Table 7. Comparison of Fuel Cell Cost Estimates for Stationary and Mobile PEM Fuel Cell Systems

		Stationary 50-kW PEM Fuel Cell System		Mobile 50-kW PEM Fuel Cell System
Production Quantity		100	10,000	300,000
Fuel Cell Stack Cost	$	$18,395	$9,962	$903
	$/kW	*367.9*	*199.24*	*18.05*
Ancillary Components	$	$6,270	$5,585	$939
	$/kW	*125.4*	*111.7*	*18.77*
Total Fuel Cell System Cost	$	$24,665	$15,547	$1,841
	$/kW	*493.3*	*310.94*	*36.82*
Fuel Cell Assumptions				
Fuel Cell Degradation		6%/year		0
Lifetime	hours	87,600		5,000
Platinum Loading	mg/cm^2	0.6		0.25
Cell Power Density	W/cm^2	0.6		1.0

(Platinum price = $380/troy ounce)

Inverter/Controller Cost Estimates

The direct current from the fuel cell must be inverted to alternating current for use in the building, and an electronics control package will be required to operate the fuel cell system. As shown in Figure 2, DC to AC inverters for the photovoltaic business are sold at prices near $1,000/kW for 3-kW residential systems. If we assume a retail markup of 66%, then the cost would be in the range of $600/kW. If we assume that one inverter company has sold only 1,000 of these units, then further cost reductions could be expected at the 10,000 quantity level. With an 85% progress ratio and 10,000 cumulative production, the cost would be 58% of \$600/kW or \$350/kW.



This estimate for the inverter cost is consistent with a 1981 projection by SAI showing inverter costs in the range between \$180/kW and \$225/kW by the 1990-2000 time period, after correcting for inflation. No inverter sizes were specified, but these costs were associated with large photovoltaic systems where the cost per kW would be expected to be less than for small home-sized inverter systems. For the 50-kW commercial building fuel cell, we assume the lower price of \$180/kW for 10,000 quantity production.

These estimates of \$180 to \$350/kW may seem high by automotive inverter standards. For example, DOE has set a goal of reducing vehicle inverter systems to \$7/kW by 2004 (DOE 1998). However, the vehicle inverter would be produced in much larger quantities, and they have no requirements for synchronization with the utility grid or for fault protection. Even so, the two order of magnitude gap between these two estimates deserves further exploration.

The resulting inverter cost estimate is given by:

$$C_{inv} = \$542 + 169x\,P_N$$

Steam Methane Reformer Cost Estimates

DTI has also estimated the mass production cost for a stationary steam methane reformer system with composite metal membrane gas cleanup (Thomas 1998b). The estimated cost at a production volume of 6,000 units is:

$$C_{SMR} = \$5,639 + \$129xQ(kg/day)$$

where Q = the reformer output capacity in kg of hydrogen per day. A reformer would need a capacity of 40 kg/day to supply 50 FCVs, assuming a 63% capacity factor and 0.5 kg/day/FCV consumption. This 40 kg/day capacity reformer would cost about \$10,800 at the 6,000 production level, or about \$9,580 for 10,000 units. The relatively low plant capacity factor (63%) is based on the assumption that the fueling station would experience seasonal, weekly and statistical load fluctuations in hydrogen gas demand. With greater hydrogen storage or less demand variation, the reformer cost per kg of hydrogen would be reduced.

For the cogeneration systems evaluated here, we assume steady-state reformer operation: the reformer puts out the maximum required hydrogen flow rate to provide the peak electrical capacity of the fuel cell. Since the electricity demand is rarely at peak power (the electrical load has low capacity factor), the excess hydrogen produced is stored onsite for later dispensing into the FCV tanks. The total capacity factor (to produce both electricity and hydrogen) of the reformer is therefore improved, reducing the cost per quantity of hydrogen produced. In the best case all this excess hydrogen is sold to FCV owners, maximizing return on investment. We also evaluate cases with fewer FCV customers, reducing the economics for the project.

For a 3-kW$_e$ home fuel cell system, the reformer needs to produce about 0.18 kg/hour of hydrogen on the average, which is only 11% of the 50-FCV reformer output analyzed previously. The estimated reformer cost assuming 63% capacity factor (6.8 kg/day capacity) would be $6,523 at 6,000 units or $5,790 at the 10,000 level. With continuous reformer operation and onsite hydrogen storage, the cost would be reduced to $6,200 and $5,500 -- a small decrease since only 10% of the cost scales with output for these very small reformer systems.

We also evaluated a scaled down version of the IFC PC-25 reformer, which has a larger hydrogen output at approximately 12 kg/hour, or 78 times more than needed for the home fuel cell system. With the scaling parameters we had assumed for the PC-25, the cost of the 3 kW$_e$ reformer system with PSA gas cleanup would be $10,500. However, we have much less confidence in this value, given the large scaling range. We therefore use the $5,790 cost estimate for the residential fuel cell system in mass production.

Compressor Cost Estimates

DTI has estimated the mass production cost of a water cooled 8-stage hydrogen compressor based on an eight cylinder automobile engine block, suitable for a 50-car fueling station. This compressor is estimated to cost $5,795 for a hydrogen flow rate of 2 kg/hour, assuming compression from atmospheric pressure to 41.4 MPa (6,000 psi) and 6,000 units produced. To compress only 0.18 kg/hour needed for a 3-kW home fuel cell system, the electric motor driving the compressor could be ten times lower power, and the compressor itself would have lower cooling requirements. Costs could be reduced to $4,000 by eliminating the liquid cooling and radiator and by using the smaller motor. If we assume an 85% progress ratio, then the cost would be reduced to $3,520 for 10,000 home fuel cell systems.

The Electrolyser Corporation has also estimated the cost of a small scale compressor for hydrogen refueling under contract to the Ford Motor Company, based on the FuelMaker natural gas fueling system. This FuelMaker now sells for US$2,700 with annual production in the range of 1,000 units, and can supply about 0.22 kg/hour of hydrogen, enough for the home fuel cell application. Although the FuelMaker only pressurizes to 3,600 psi now, Electrolyser is developing a higher pressure system operating on hydrogen. They project mass production costs of $1,875 for this hydrogen compressor capable of fueling vehicle tanks at 5,000 psi, assuming 10,000 quantity production. We therefore have a range of cost estimates between $1,875 and $3,520 for the residential compressor in 10,000 unit production quantity.

The 50-kW fuel cell system would require a compressor capable of handling 3.2 kg/hour when no electricity was being produced and all hydrogen was diverted to the compressor, or 50% larger than the 8-stage compressor described above. The compressor cost scales very little with output hydrogen flow at the 10,000 quantity level of production:

$$C_{comp.} = \$4{,}526 + \$286xQ(kg/h)$$

where Q = the hydrogen flow at peak power in kg/hour. This equation only applies for hydrogen flow rates in the range between 2 to 4 kg/h. For the 50-kW fuel cell system, the compressor to handle the full output from the reformer (3.2 kg/h) would cost about $5,500.

Hydrogen Storage Cost Estimates

For the typical home situation, we assume that the hydrogen is compressed slowly at night into the vehicle tanks. No hydrogen storage is required in this case. However, if the customer wants to fast-fill his vehicle, and for larger building applications, then on-site storage would be required. In this case we assume hydrogen is compressed to 6,000 psi and stored in carbon fiber wrapped composite tanks. We assume cascade filling with three separate hydrogen tanks. From our previous work for DOE (Thomas 1998b), the cost of a single stationary hydrogen tank including a solenoid valve and pressure relief device is given by for 10,000 quantity production volume.[5]

$$C_{ST} = \$284 + \$192xH(kg)$$

For stationary storage more than one tank is usually required for cascade filling -- the vehicle tank is first filled from the lowest pressure storage tank. The control system then sequentially switches the car tank to higher pressure storage tanks until the maximum pressure is reached. We generally assume that the peak pressure is in the range of 6,000 psig for vehicle tanks rated at 5,000 psig. However, with cascade filling, not all hydrogen can be utilized. Some hydrogen is left in the storage tank when its pressure drops too low for efficient vehicle tank filling. Tom Halvorson at Praxair has analyzed cascade filling in detail, and concluded that 50% utilization is a practical level (Halvorson 1996). The resulting cascade system cost is given by

$$C_{CT} = \$284x\,N_t + \frac{\$192x\,N_{FCV}\ x\,H_{FCV}\ x\,S_f}{U_c}$$

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[5]The original cost estimate was made for 6,000 unit production; we have assumed a low 95% progress ratio to convert to 10,000 unit production for storage tanks, which reduced cost by only 3.3% relative to the 6,000 unit level of production.

where N_t = the number of tanks in the cascade (default is six),
N_{FCV} = the number of fuel cell vehicles supported by the system,
H_{FCV} = the average daily hydrogen consumption by one FCV (default is 0.5 kg/day),
S_f = the total cascade storage fraction of average daily demand (default is 0.8), and
U_c = the hydrogen utilization fraction (default is 0.5).

For a stationary fuel cell system supporting 50 FCVs, the cost of the cascade storage system would then be \$9,380 at the 10,000 production level. We use a rather small progress ratio of 95% for these composite fiber wrapped tanks to extrapolate back to the 100 quantity level in the model.

Halvorson et al. have also devised an alternative tank filling scheme based on booster compression. In this case the hydrogen is stored at an intermediate pressure such as 3,000 psig. Vehicle tanks are filled first from this intermediate pressure storage. The car tanks are then "topped off" with hydrogen from the booster compressor. The booster compressor is also used to fill the stationary tanks to their 3,000 psig rated level from the reformer, using various stages of the compressor to serve the different compression tasks. While the compressor may be more complex, this booster filling system eliminates the need for very high pressure stationary storage. In addition, most of the hydrogen can be utilized, reducing the total volume of storage required, and not all of the hydrogen is compressed to the maximum 6,000 psig pressure, saving on compression electricity costs. This booster compressor filling system may reduce system and operating costs, but we have not had time to fully analyze this system under this task. We use the more conservative cascade filling system in this model.

Hydrogen Dispenser Cost Estimates

For the overnight, slow-fill residential case, the dispenser system would include the fueling hose and connector, a pressure gauge, grounding system, control switches, a solenoid valve, a hydrogen sensor and alarm system and a housing. We assume that these components would be integrated into the compressor system control electronics. We project mass production cost of \$625 for these components.

For the fast fill case, two extra pressure sensors would be required to monitor the three storage tanks, and a more elaborate control system would be required to sequentially fill the vehicle tank from the three storage tanks. We estimate an extra cost of \$460, or a total of \$1,085 for the fast fill residential case in mass production.

For the larger building system supplying multiple vehicles, the dispensing system would presumably be an independent island, similar to gasoline fueling stations. The industrial gas suppliers have previously estimated a cost of \$42,000 for a refueling island in low production volumes. We project that costs could be reduced to \$14,300 with 100 quantity production and to \$4,800 per dispensing connection for 10,000 production volumes, assuming an 85% progress ratio. The dispenser cost then scales with fuel cell power according to:

$$C_{disp} = \$850 + 79x\, P_N$$

Stationary Fuel Cell System Economic Evaluation

We have evaluated the economics of building fuel cell systems to deliver three products: electricity, heat and hydrogen. We evaluated performance in four regions of the country: California, New York, Massachusetts and Alaska -- the first three due to the zero emission vehicle mandate and Alaska because of its extremely favorable ratio of electricity to natural gas cost.

Financial Assumptions

We have analyzed the project economic performance from two perspectives: first we calculate the price of electricity necessary to yield a 10% real, after tax return on the fuel cell investment. If this target electricity price is less than the prevailing utility price in the region, then the project would be economic. We then estimate the price of hydrogen required to produce a 10% return on the investment in the compressor, storage and dispenser. The resulting hydrogen price is then compared with the price of gasoline per mile driven.

Next we reverse the calculation, fixing the price of electricity at the prevailing regional price, and setting the price of hydrogen equivalent to the price of gasoline. The model then estimates the system return on investment for four primary cases:

* selling electricity only
* selling electricity and heat
* selling electricity and hydrogen
* selling electricity, heat and hydrogen

The basic financial parameters are summarized in Table 8. The first four parameters are held constant for all analyses reported here. For the first economic case (fixed return of 10%), the annualized fraction of capital that must be recovered in the price of electricity varies depending on the expected life of the component. For example, the storage tanks with an expected life of 20 years

Table 8. Financial Assumptions

Insurance Rate	0.002		
Property Tax Rate	0.012		
Inflation Rate	0.02		
Marginal Corporate Income Tax Rate	0.26		
After-Tax Real Rate of Return (to set price of electricity in first economic analysis case only)	0.1		
Lifetime (years)	10	15	20
Annual Capital Recovery Factor:	0.206	0.177	0.166

requires a 16.6% annual capital recovery to yield the ten percent return, while the fuel cell system with a 10-year life expectancy requires a 20.6% per year capital recovery, all assuming straight-line depreciation for tax purposes, as shown in the last two rows of the table.

The assumed operation and maintenance (O&M) costs and lifetimes for each component are summarized in Table 9. The O&M costs are expressed as a fraction of the capital cost for each component.

Table 9. Operation and Maintenance Costs and Lifetime Estimates

	Operation & Maintenance Costs	Lifetime (years)
Steam Methane Reformer	0.035	15
Fuel Cell System	0.03	10
Inverter/Control System	0.01	20
Compressor System	0.045	10
Storage Tanks	0.025	20
Connector/dispenser	0.05	15

Economics of a 50-kW Commercial Building Fuel Cell System

Electricity Price to Generate 10% Return

The price of electricity necessary for a 10% real, after-tax ROI was calculated for four states for three different system production volumes: an initial system[6], systems produced in 100 quantities, and production at the 10,000 level. The results are summarized in Table 10 assuming a 50-kW fuel cell system -- the net output peak AC power to the building is 50 kW. We assume that the building has an electrical capacity factor of 60%, similar to the maximum factors for hotels and hospitals. The results reported here would therefore not apply to typical office buildings, schools or shopping malls that have much lower electrical capacity factors. The natural gas and electricity prices are average prices for 1998 (EIA-1999). The electricity prices are the total revenues from a customer divided by the energy used in kWh. These electricity costs therefore include the commercial demand charges for power demand (kW) and any fixed monthly charges, and are larger than the actual average energy charges in cents/kWh.

The results illustrate that selling only electricity would be quite attractive in Alaska if 10,000 systems were built, with the fuel cell electricity selling at 6.6 cents/kWh compared to the average utility electricity charge equivalent to 9.2/kWh. The 50-kW system would be marginally attractive in New York (due to the high electricity rates in New York), but would not achieve our 10% return criterion in California or Massachusetts

[6] The initial cost does not include any R&D recovery. The very first systems deployed in demonstration projects would undoubtedly cost much more than the $200,100 assumed here.

even if 10,000 systems were built.

Table 10. Commercial Electricity Prices Required for 10% ROI vs. Actual Regional Prices

	Commercial Natural Gas Price ($/MBTU-HHV)	Average Commercial Electricity Prices (Cents/kWh)	Required Electricity Price for 10% Real, After-Tax Return on Investment (Cents/kWh)		
			1 Qty.	100 Qty	10,000 Qty
Alaska	2.41	9.2	21.4	10.8	**6.6**
California	6.26	8.7	26.1	15.7	11.4
Massachusetts	6.62	9.4	26.7	16.1	11.9
New York	6.64	11.0	26.7	16.1	11.9
Fuel Cell System Cost ($)			$200,100	$85,070	$38,900
Fuel Cell System Cost ($/kW)			4,002	1,701	778

Since the maximum expected electrical capacity factor is only 60%, the steam reformer can be operated the other 40% of the time to produce hydrogen. We assume that a hydrogen compressor, storage tanks and a dispenser to supply FCVs are purchased. The cost of hydrogen to return 10% on this investment is then calculated, as summarized in Table 11. The cost of hydrogen is expressed in $/gallon of gasoline-equivalent, taking into account the higher fuel economy for a hydrogen FCV compared to a gasoline ICEV. We assume that the FCV will have 2.2 times higher energy efficiency than a gasoline ICEV. A hydrogen price of $1.20/gallon equivalent would produce the same cost per mile for a hydrogen FCV as for a gasoline ICEV. The prices shown in Table 11 do not include road taxes. We assume here governments (Federal and state) would try to encourage the use of hydrogen initially by exempting this superclean fuel from highway taxes.

Unlike the case for electricity sales only, the hydrogen produced off-peak is competitive with gasoline prices today, even for the case of only 100 systems produced. Eventually, as hydrogen became a more common fuel, road taxes might be added. In this case the hydrogen must be equal to or less than the wholesale price of gasoline, currently in the region of $0.80/gallon in the U.S. As shown in Table 11, hydrogen produced in all four regions approach the wholesale price of gasoline if 10,000 systems were produced, and even 100 unit production would be sufficient to produce hydrogen near the wholesale gasoline price in Alaska, again due to the very inexpensive natural gas at $2.41/MBTU. These hydrogen prices assume that all of the hydrogen produced when the fuel cell is below peak power is sold. This hydrogen could support about 44 full size passenger vehicles.

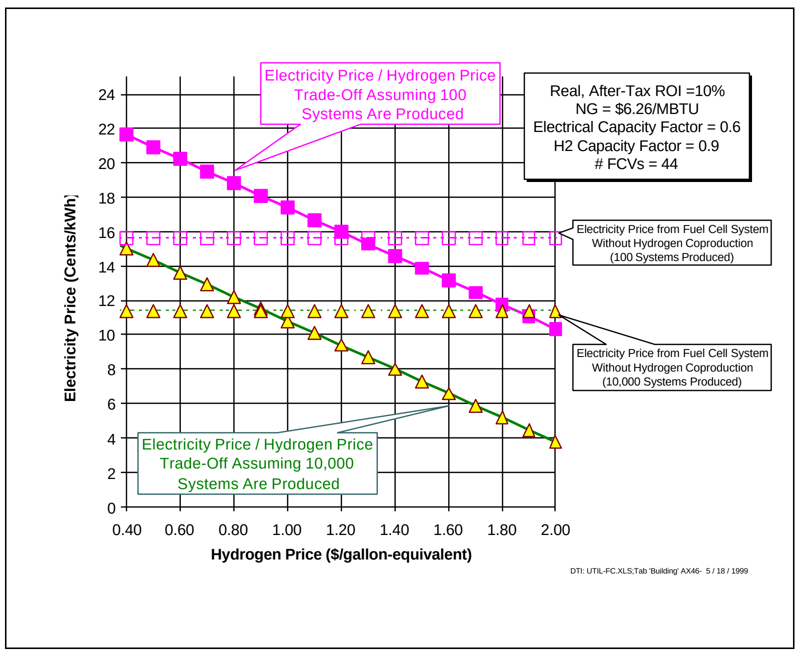
Since the price of hydrogen is below the retail (fully taxed) gasoline price, the fuel cell owner would have the option of raising the price of hydrogen to subsidize the price of electricity. The project could then achieve its 10% ROI selling both products. This tradeoff is illustrated in Figure 2 for the case of average

California utility prices. At the 10,000 unit production level, electricity would have to sell at 11.4 cents/kWh in California (lower horizontal line in Figure 2), which is above the average commercial rate of 8.7 **4**/kWh.

Table 11. Hydrogen Prices Required for 10% ROI on the Compressor, Storage and Dispenser System

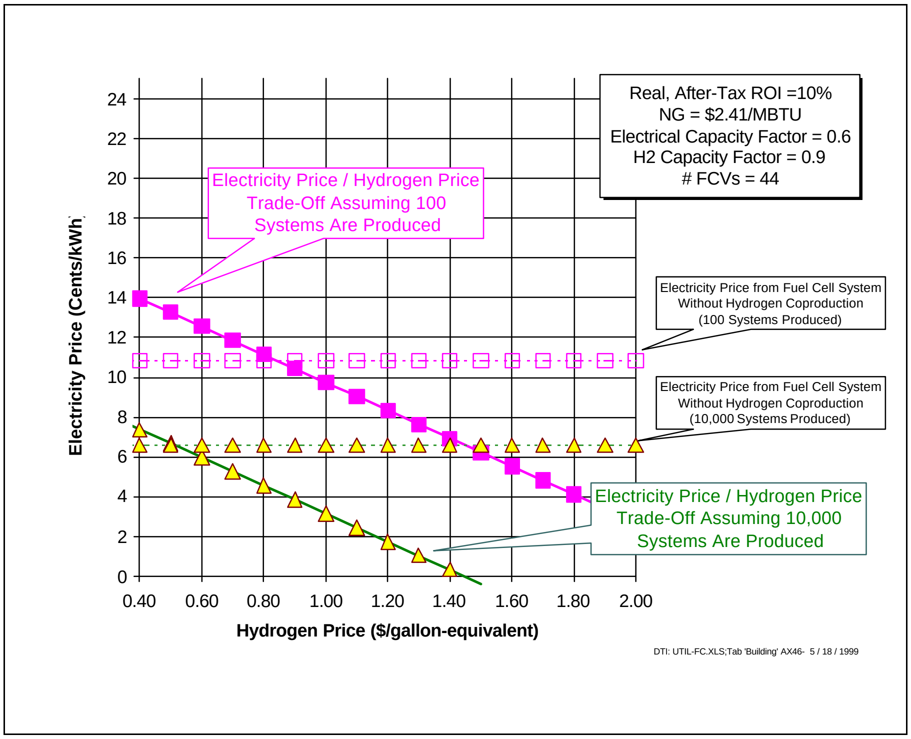
	Commercial Natural Gas Price ($/MBTU-HHV)	Required Hydrogen Price for 10% Real, After-Tax Return on Investment ($/gallon of gasoline-equivalent)		
		1 Qty.	100 Qty	10,000 Qty
Alaska	2.41	1.78	**0.84**	**0.50**
California	6.26	2.18	1.24	**0.91**
Massachusetts	6.62	2.22	1.28	**0.94**
New York	6.64	2.22	1.28	**0.95**
Hydrogen System Cost ($)		107,020	41,880	18,690
Hydrogen System Cost ($/kW)		2,140	838	374

If the hydrogen price were increased from $0.91/gallon-equivalent (which would return 10% on the hydrogen equipment) to $1.30/gallon, then the price of electricity could be reduced to 8.7 **4**/kWh (lower diagonal line in Figure 1).

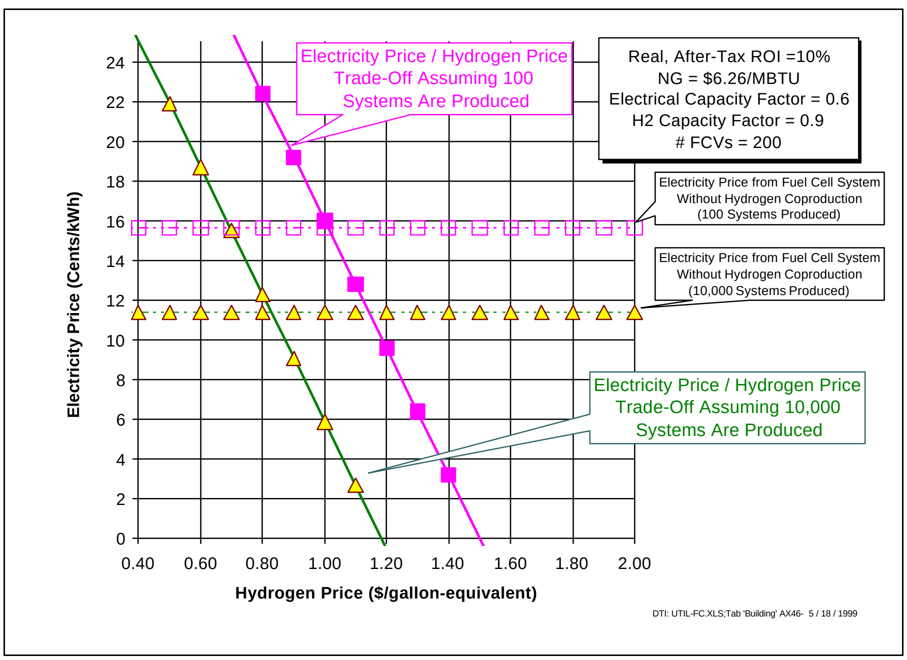


The same tradeoffs for Alaska are illustrated in Figure 2. In this case electricity is already below the prevailing rate of 9.2 **4**/kWh at the 10,000 production level. Adding hydrogen provides even greater flexibility in terms of pricing electricity well below the going rate of 9.2 **4**/kWh while at the same time selling hydrogen at less than $1.20/gallon-equivalent. Even the 100-production level provides near-competitive rates selling electricity at 9.2 **4**/kWh and hydrogen below $1.10/gallon of gasoline-equivalent.

Estimated Return with Oversize Reformer

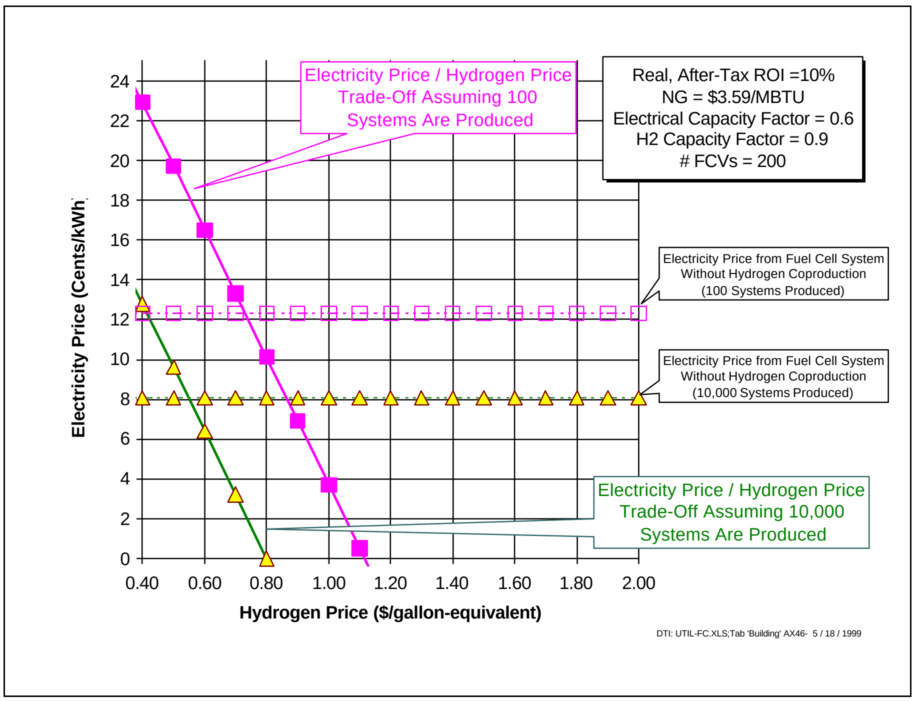


The return on investment could be increased in those situations where more hydrogen could be sold by making a larger steam methane reformer. This oversize reformer would produce all of the hydrogen needed to supply the specified electrical output from the fuel cell system in addition to supplying extra hydrogen at all hours, not just during low electrical demand hours. The model calculates the necessary hydrogen to run the fuel cell system and the cell compressor system to compress all hydrogen produced to 6,000 psi, on the assumption that the hydrogen will be stored onboard vehicles at 5,000 psi. In addition, the fuel cell electricity is used to run the steam methane reformer. Hence the model calculates the extra hydrogen necessary to supply electricity to both the reformer and the hydrogen compressor.



The electricity/hydrogen price tradeoffs are summarized in Figure 1 for a 50-kW fuel cell system in California with the steam methane reformer oversized to produce enough hydrogen for 200 fuel cell vehicles. That is, the reformer would supply 44 FCVs with hydrogen from the off-peak hydrogen production, plus enough hydrogen for 156 more FCVs with a constant hydrogen output over 24 hours.[7] If hydrogen could be sold at $1.20/gallon of gasoline-equivalent, then the price of electricity to bring our goal 10% ROI could be reduced from just under 16 **4**/kWh down to 10 **4**/kWh for 100 quantity production. If 10,000 such fuel cell systems were built, then hydrogen could be sold at $1.00/gallon-equivalent, and electricity could be sold profitably at 6 **4**/kWh. In other words, both hydrogen and electricity could be sold below the competing price if a market for hydrogen equivalent to 200 FCVs were available on-site. These 200 FCVs would consume on the average 100 kg/day (or 12 GJ/day (LHV) or 1,200 standard cubic meters/day or 42,320 standard cubic feet/day) of hydrogen.[8]

The data in Figure 0 are based on average 1998 commercial natural gas prices in California of $6.26/MBTU (HHV). If the building owner could obtain natural gas at the prevailing industrial gas prices in California at $3.59/MBTU, then the economics improve dramatically as shown in Figure 1. Now even the 100-unit production run would provide the 10% real, after-tax return on investment with hydrogen selling at $1.00/gallon-equivalent and electricity selling at only 4 **4**/kWh. At the 10,000 production level, the price of hydrogen could be reduced to only 70 **4**/gallon-equivalent, near the wholesale cost of gasoline, with electricity selling at only 3 **4**/kWh. Thus the hydrogen could even accommodate highway taxes and still compete with gasoline in a conventional vehicle.



We conclude that hydrogen could be a very effective co-product to fuel cell-generated electricity as long as the building owner could obtain industrial natural gas prices (on the order of $3.50/MBTU) and has a need for hydrogen equivalent to supporting 200 fuel cell vehicles.

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[7]The model assumes a 90% reformer capacity factor and a 95% plant availability to account for down-time, so the reformer capacity is increased by a factor of 1.17 to account for down-time and uneven demand for the hydrogen product.

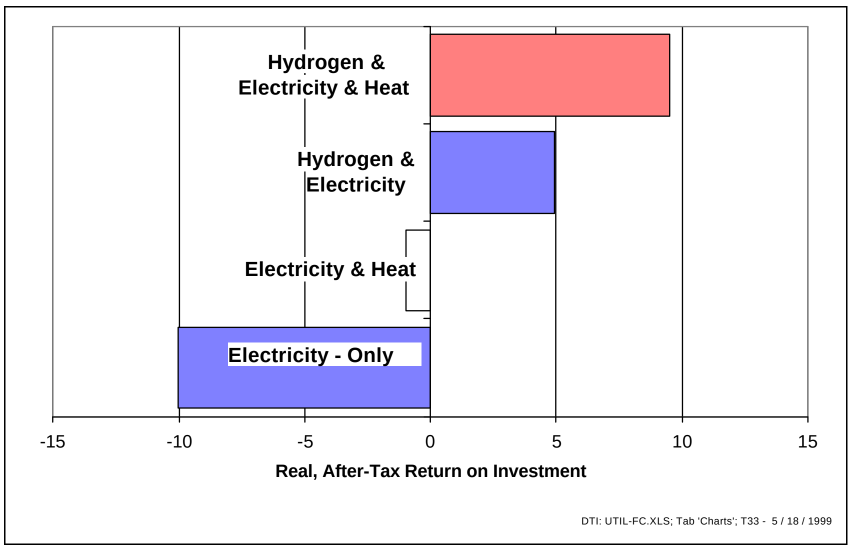
[8]This consumption assumes 12,000 miles traveled per year and 66 miles per gallon of gasoline-equivalent fuel economy for the 5-passenger fuel cell vehicle.

Estimated Return Based on Current Utility Rates

As an alternative to evaluate the economics of the building fuel cell system, we can fix the price of natural gas at the prevailing rate for commercial establishments in the region, and calculate the return on investment assuming that the major revenue for the project is the avoided cost of electricity for the building. The avoided electricity cost is set by the prevailing price of commercial electricity in the region.

As a second step, we estimate the avoided heating cost for space heat and for water heating if the fuel cell system waste heat is used to offset the building thermal load. The return on investment is then recalculated using avoided electricity and avoided heating costs as the revenue for the project. We assume that the space heating system in the building has 90% efficiency, and we assume that the heat from the fuel cell system is recovered at 60% efficiency. For each state, the model calculates the lesser of the building heat load or the fuel cell recoverable waste heat. For northern buildings we assume that the building thermal load is 70% of the annual electrical consumption. For southern states thermal loads average about 47% of the building electrical load, including both hot water and space heating. The model then calculates the avoided natural gas costs for the heat supplied by the fuel cell system.

Finally, we produce hydrogen during the off-peak electrical times, and sell the hydrogen at $1.20/gallon of gasoline equivalent, creating a third revenue stream for the project (in addition to avoided electricity and avoided natural gas heating costs). The results of these calculations are summarized in Figure 2 for the case of California at the 10,000 quantity production level.



If we only count the avoided cost of electricity, then the project loses money -- the cost of amortizing the fuel cell system equipment plus operating expenses exceed the avoided cost of electricity, or a negative ROI. If we cogenerate heat for the building, the ROI improves but is still negative in a southern state like California. (The ROI would be about a positive 1.5% in a northern U.S. building with California utility rates.) If we add hydrogen to electricity (no heat cogeneration), then the ROI increases to 5%. Combining electricity, hydrogen and thermal cogeneration increases the ROI to 9.5% (south) to 10.8% (north). In effect hydrogen sales make the project economic.

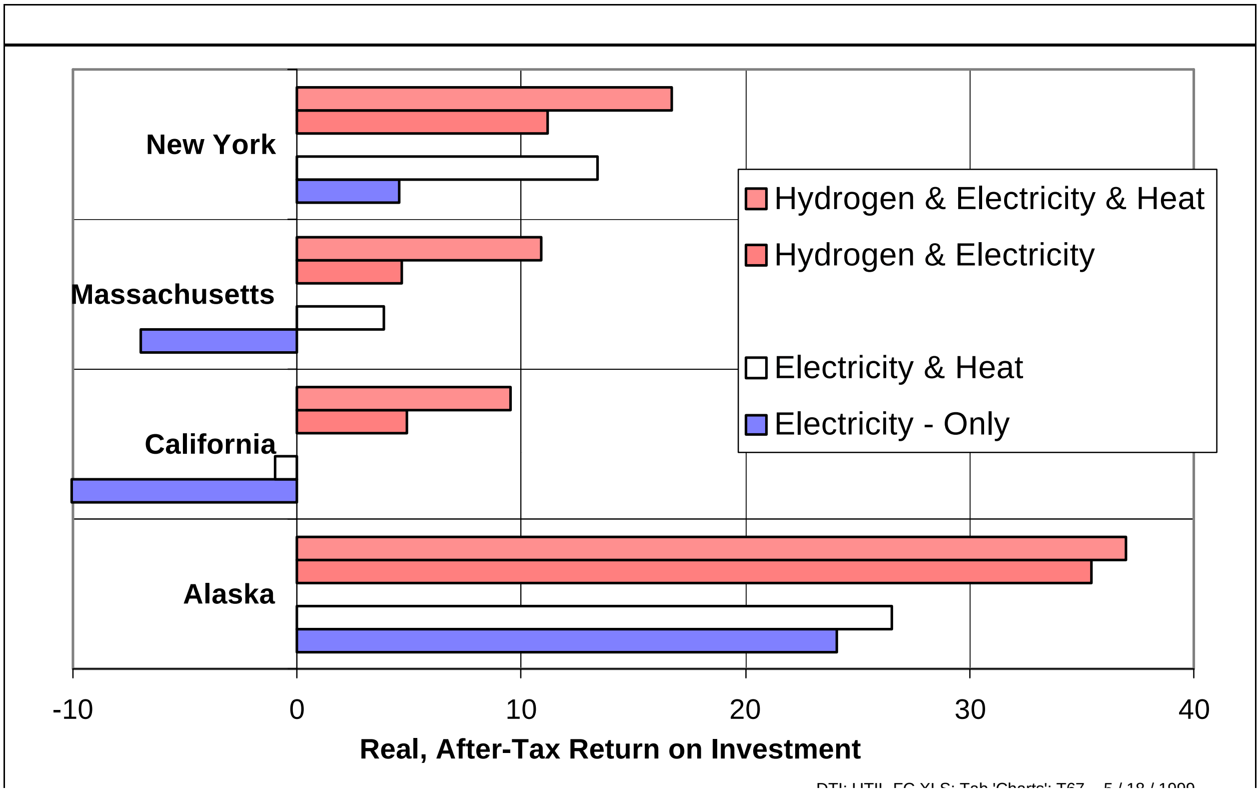
The real, after-tax return on investment criterion used here is rather stringent, accounting for both taxes and inflation. For frame of reference, the various rates of return are compared in Table 12 for the California commercial case used to generate the previous figures. The 10.8% real, after-tax return for the case of electricity, hydrogen and heat cogeneration is equivalent to 13.0% after-tax return in current dollars (with the 2% inflation assumed here), and it is equivalent to 16.6% ROI before taxes (with the 26% marginal corporate income tax rate assumed here).

The same real, after-tax ROI calculations shown in the previous figure are summarized in Figure 2 for all four states. Massachusetts is very similar to California, since they have approximately the same electricity and

SMR Electricity	kWh/kg	1.64	
Purchased Electricity Cost	cents/kWh	8.8	
Purchased Electricity Demand Charge	$/kW/month		
Natural Gas Cost	$/MBTU	3.6	
Hydrogen Sales Price	$/gallon-eq.	1.2	
Fuel Cell System Net AC Power Out	kW	50	
Insurance Rate		0.005	
Property Tax Rate		0.015	
Inflation Rate		0.02	
Marginal Corp. Income Tax Rate		0.26	
After Tax Real Rate of Return		0.1	
Plant Availability		0.95	
Electrical Load Capacity Factor (Commercial / Residenti		0.6	0.27
Number of FCVs		200	
Fuel Cell Vehicle Fuel Economy	MPG-equiv.	66	
Annual Miles Traveled	miles	12000	
Gasoline Lower Heating Value	MBTU/gallon	0.115	
Hydrogen Lower Heating Value	MBTU/kg	0.1136	
Fuel Cell Parasitic Losses	Fraction	0.05	
Hydrogen Production Capacity Factor	Fraction	0.9	
Building NG Furnace Efficiency	Fraction	0.9	
Building Thermal Load/Electrical (N/S)	Fraction	0.7	0.47
Fuel cell system degradation	%/yr	0.06	
Fuel Cell fixed cost ["B" 100/10K units]	$	1311.3	428.51
Fuel Cell power-dependent cost ["A"]	$/kW	811.77	454.45
FC Power & Pt-dependent cost	$/	16	
Market Price of Platinum	$/troy ounce	380	
Pt Salvage Fraction for Fuel Cell System		0.5	
Pd Loading	mg/cm^2	0.6	
Cell Peak power density	W/cm^2	0.6	
FC Ancillary Fixed Cost [100 & 10K units]	$	3343.5	2980.2
FC Ancillary Linear Cost [100 & 10K units	$/kW	39.94	35.65
FC Ancillary Quad. Cost [100 & 10K units	$/kW^2	-0.0454	-0.0422

Table 12. Comparison of Rates of Return for California Commercial Building Case (%) (for 10,000 Production Level)

	Before Tax Return	After Tax Return	Real, After Tax Return
Electricity Only	-	-8.2	-10.0
Electricity & Heat - California	1.17	1.0	-1.0
[Electricity & Heat - Northern Building]	4.5	3.4	1.5
Hydrogen & Electricity	9.0	7.0	4.9
Hydrogen & Electricity & Heat - California	15.1	11.7	9.5
[Hydrogen & Electricity & Heat - North]	16.6	13.0	10.8



natural gas commercial prices. A 50-kW fuel cell system in New York is more profitable due to the average commercial electricity price of 11.0 cents/kWh, compared to 9.4 **4**/kWh average in Massachusetts -- the New York fuel cell project avoids higher electricity rates by installing the fuel cell system. The project reaches our 10% ROI goal with electricity and heat cogeneration, even without hydrogen coproduction. Adding hydrogen sales boosts the estimated ROI above 15% including thermal cogeneration. Alaska ROIs exceed 25% without hydrogen and 35% with hydrogen cogeneration.

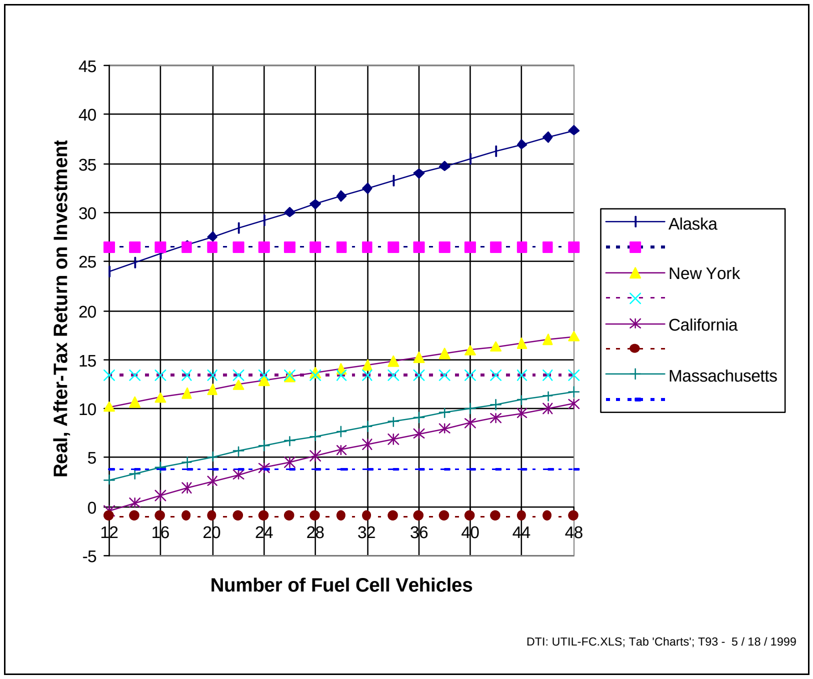
Return on Investment vs. Number of FCVs

The excess hydrogen produced from the 50-kW fuel cell system is enough to supply 44 FCVs during the 40% electricity off-peak period. We assumed above that each fuel cell system supported exactly 44 FCVs. If fewer vehicles were available, then profitability would decline. Even with 44 FCVs assigned to the fuel cell system, there would need to be some adjustment for variable hydrogen demand over time.

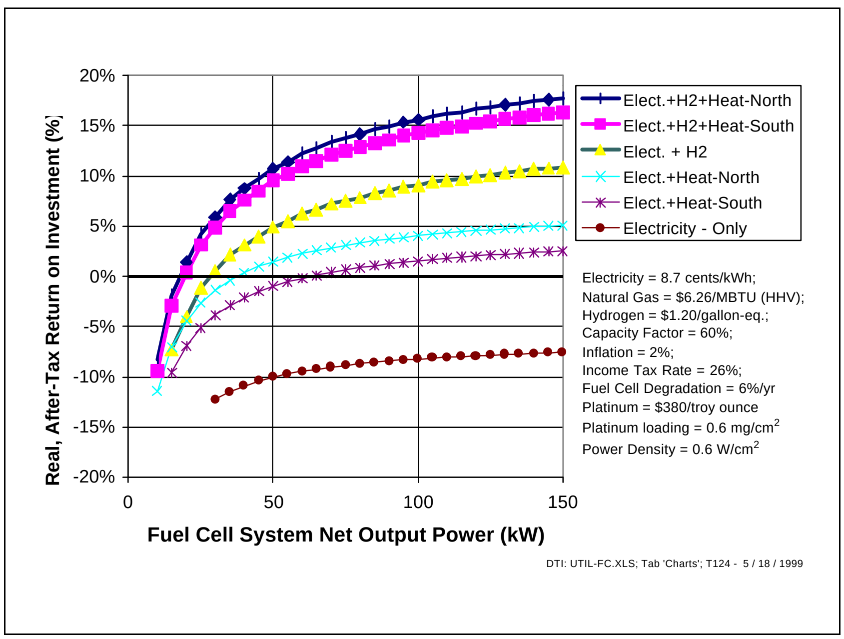
The ROIs are summarized in Figure 2 as a function of the number of fuel cell vehicles supported by the building fuel cell system for the four states analyzed here. For each state, the horizontal line shows the ROI without hydrogen, but including thermal cogeneration. The diagonal line shows the ROI when the hydrogen compressor, storage tanks and dispenser system is added. For Alaska (top lines), the ROI is improved with hydrogen as long as more than 18 FCVs are supported by the facility. For New York, at least 25 FCVs are required for a net gain with hydrogen, while Massachusetts benefits from more than 16 FCVs and California would have higher return for more than 12 FCVs. Of course these same economic benefits would be obtained if the hydrogen were consumed on-site for an industrial user needing extra hydrogen.

Return on Investment vs. Size of Fuel Cell

All data presented previously assume a 50-kW net AC power to the building. Producing larger fuel cells would improve the economics, since the cost per kW of power decreases with increasing size. Conversely, the economics will diminish for small systems. The return on investment is shown in Figure 1 as a function of the size of the fuel cell system sited in California. The top three curves all include hydrogen sales at the maximum usage, assuming that there are enough FCVs (or other industrial use) to absorb all of the off-peak hydrogen generation.



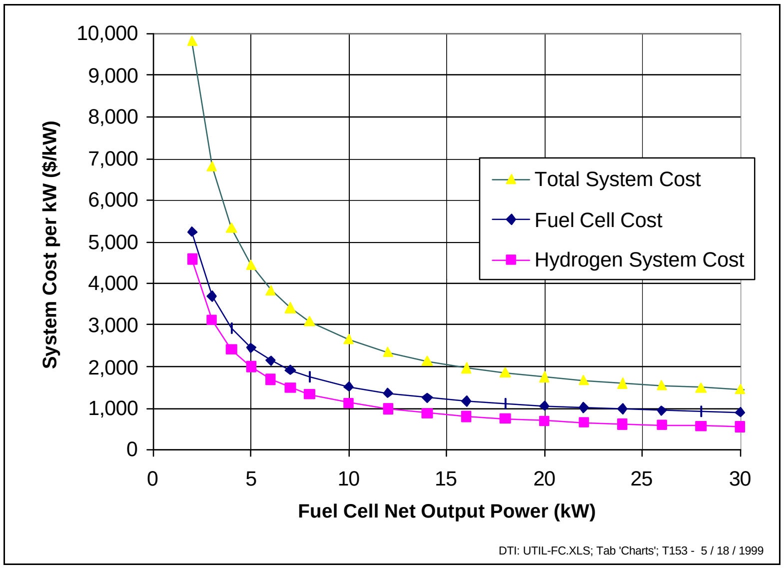
With our cost and financial assumptions the stationary fuel cell system never generates a positive return in California, assuming average California commercial electricity and natural gas rates. It is always less expensive to pay the average existing utility rates then to purchase and operate a stationary fuel cell system. Adding heat cogeneration to displace some natural gas heating consumption in the building approaches 5% ROI in northern climates for the larger (>150 kW) systems. Otherwise hydrogen sales are necessary to make a significant return on investment.



Economics of a 3.4-kW Residential Fuel Cell System

The previous figure clearly demonstrates that the project economics fall substantially for commercial building fuel cell systems below 15 kW. The average U.S. residence only requires 3.4 (North) to 3.7 (South) kW peak, with an average demand of only 900 watts to 1.07 kW, corresponding to electrical capacity factors between 24 to 27%. The residential fuel cell system has the economic advantage of competing with higher residential electrical prices than the commercial system, but this is more than offset by the higher fuel cell system costs per kW, the much lower capacity factors and the higher natural gas costs to residential consumers.

The estimated system capital costs as a function of fuel cell system size are shown in Figure 2. Below 5 kW, we project system costs approaching $10,000/kW, even at production volumes of 10,000 units. The elements of these cost estimates are shown in Figure 3 for the residential sized systems.



These small fuel cell cost estimates may be excessive since we costed the larger systems and scaled down. From the top down cost analysis, it appears that many components will not scale down in cost as they are made smaller. But if the system is designed initially for the smaller residential system, new configurations may be invented that avoid these scale down difficulties. Several companies are reportedly developing home fuel cell systems, so they must be convinced that lower prices are achievable. For example, Northwest Power Systems estimates that they can produce a steam methane reformer in the 3 to 5 kW size for $150/kW to $350/kW "when manufactured in volume," using a proprietary membrane gas cleanup system (Edlund 1999). Our model estimates reformer costs in the range between $1,200 to$1,800/kW in this size range at the 10,000 production level. Two other companies, Plug Power and American Power Corporation, are developing small residential PEM fuel cell systems with batteries to supply peak power (Wolk 1999). Target price for the American Power fuel cell system is $5,000 in mass production, while Plug Power is projecting initial prices in the range between $7,500 and $10,000, dropping to $3,500 in mass production for a residential system. For comparison, our cost analysis shows initial costs of $25,000 for a 3.4 kW system, falling to $11,300 at the 10,000 quantity production level. We have not included the option of a peak power battery in our cost analysis, however.[9]

[9]DTI is currently adding this battery peak power option to our cost model.

Electricity Prices Necessary for 10% Return on Investment

The economics of the residential fuel cell system are very discouraging with our cost estimates. The required electricity prices to produce a 10% ROI are summarized in Table 13 for a 3.4 net AC kW home fuel cell system,

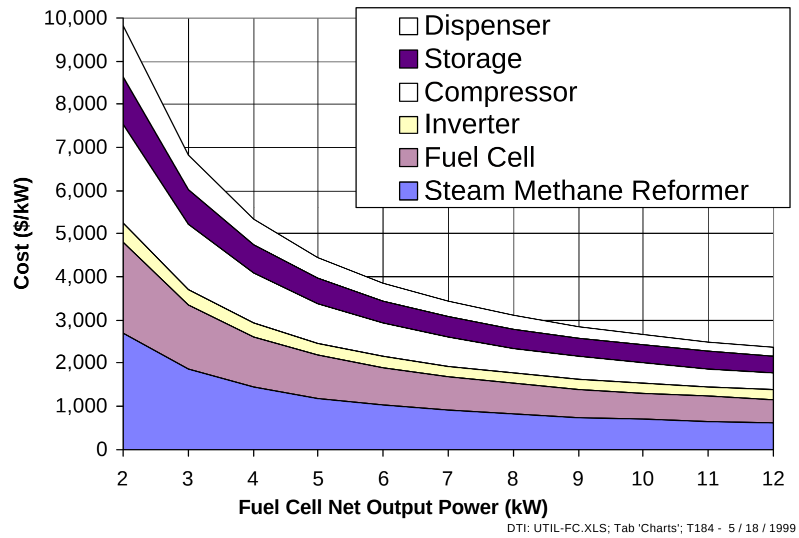


Table 13. Residential Electricity Prices Required for 10% ROI vs. Actual Regional Prices

	Residential Natural Gas Price ($/MBTU-HHV)	Average Residential Electricity Prices (Cents/kWh)	Required Electricity Price for 10% Real, After-Tax Return on Investment (Cents/kWh)		
			1 Qty.	100 Qty	10,000 Qty
Alaska	3.67	11.3	195	82.3	39.7
California	6.93	10.9	199	86.4	43.8
Massachusetts	8.58	10.6	201	88.4	45.9
New York	8.60	13.9	201	88.5	45.9
Fuel Cell System Cost[10] ($)			62,550	25,300	11,300
Fuel Cell System Cost ($/kW)			18,397	7,441	3,324

[10]The fuel cell system costs include costs for the steam methane reformer and for the DC to AC three-phase inverter and control electronics.

compared to actual average state residential electricity rates. Even in Alaska, the residential system would require a selling price of 39.7 cents/kWh after 10,000 units were built, three times the average residential rate of 11.3 cents/kWh. With the very low electrical capacity factor (27%), the reformer could be used to supply up to five FCVs with off-peak hydrogen. The resulting cost of hydrogen necessary to bring a 10% ROI is summarized in Table 14 for the residential system, assuming that five FCVS are available for each house. Despite this optimistic assumption, the cost of hydrogen produced is at best $1.57/gallon of gasoline equivalent in Alaska, well above the price of fully taxed

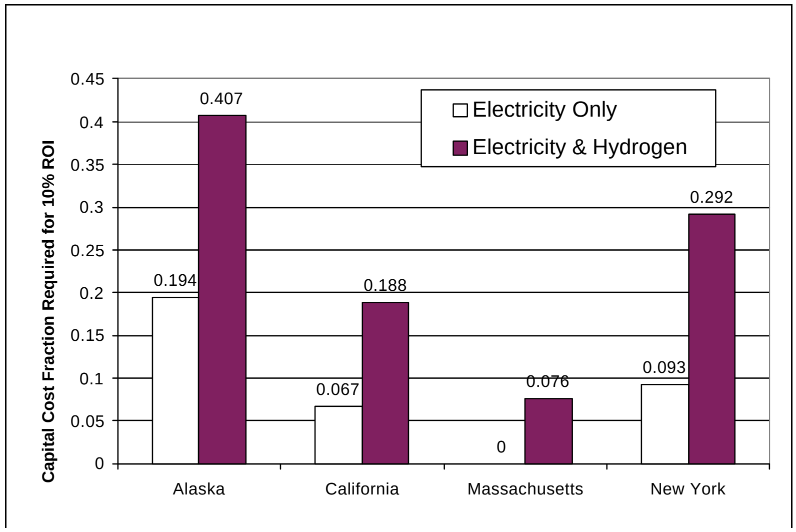
Table 14. Hydrogen Prices Required for 10% ROI on the Compressor, Storage and Dispenser System for a 3.4 kW Home Fuel Cell System with Hydrogen Coproduction

	Residential Natural Gas Price ($/MBTU-HHV)	Required Hydrogen Price for 10% Real, After-Tax Return on Investment ($/gallon of gasoline-equivalent)		
		1 Qty.	100 Qty	10,000 Qty
Alaska	3.67	8.97	3.47	1.57
California	6.93	9.31	3.81	1.91
Massachusetts	8.58	9.48	3.98	2.08
New York	8.6	9.48	3.98	2.08
Hydrogen System Cost ($)		66,430	24,170	9,500
Hydrogen System Cost ($/kW)		19,538	7,109	2,794

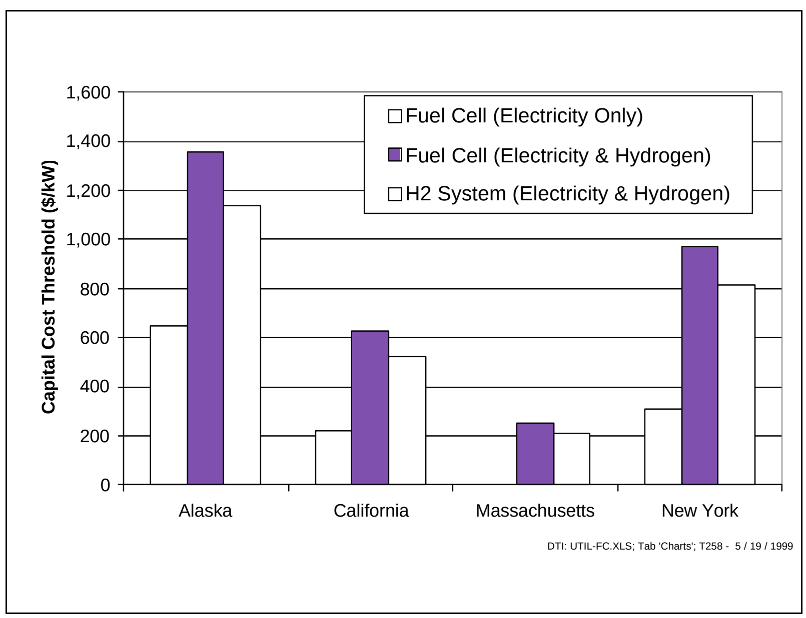
gasoline. (The average retail price of gasoline in Alaska including state and federal taxes was $1.39/gallon in January 1998.) Therefore selling hydrogen will not improve the project economics to a viable level under these cost assumptions.

Capital Cost of Residential Fuel Cell System Necessary for 10% Return

Since our cost estimates do not yield the desired return under any circumstances for a residential system, we can invert the calculation and ask what capital cost would be required to meet the financial target. The cost reduction factor was calculated for each of the four states in this study, using the average state residential electricity and natural gas prices. The results shown in Figure 2 illustrate that Alaska has the most favorable conditions. The fuel cell system costs would have to be reduced to 19.4% of the costs reported earlier for the 10,000 production level, assuming that only electricity was sold. Thus the cost of the steam methane reformer, fuel cell and inverter would have to be reduced from our estimate of $25,300 to $4,910 to reach the 10% ROI. For the hydrogen coproduction case in Alaska, the capital cost of the total system (including the compressor, storage tanks and dispenser system) would have to be reduced to 40.7% of our estimates to reach the 10% ROI goal selling both electricity and hydrogen -- in this case our total estimate of $49,470 for the fuel cell and the hydrogen system would have to be reduced to $20,130. This example illustrates again that hydrogen coproduction is valuable. The fuel cell system alone would have to be produced for $4,910 to sell only electricity, while the fuel cell and hydrogen system could cost $20,130 and still make 10% ROI for the total project.



Massachusetts has the worst residential climate for this application, since their residential natural gas prices are much higher than their commercial natural gas prices. In this case, no reduction in fuel cell system costs brings a 10% ROI. Even if the fuel cell system were *free*, it would cost more to convert natural gas selling at $8.58/MBTU, the average residential rate in Massachusetts, to electricity selling at 10.6 **4**/kWh. In all four states, the addition of hydrogen at least reduces the need to cut costs.



The actual allowable component prices in $/kW for these 3.4 kW residential systems are shown in Figure 1. The bar on the left for each state indicates the allowable cost in $/kW for the fuel cell by itself, selling only electricity. Total fuel cell system costs would need to be less than $650/kW, even in Alaska, to reach 10% returns producing only electricity. Adding the hydrogen system (assuming similar reductions in our cost estimates for the hydrogen system and also assuming five FCVs are available for every residence -- both optimistic assumptions), then the fuel cell system could be economic at $1,400/kW or less in Alaska, or less than $650/kW in California. The allowable hydrogen system costs ($/kW of electrical output from the fuel cell) are also shown as the third column on Figure 1 for each state.

Conclusions Regarding Stationary Building Fuel Cell Systems

We conclude that hydrogen cogeneration could provide an economic benefit to a commercial building stationary fuel cell system, but residential fuel cell systems are not promising. Specifically, for commercial building fuel cell systems, we find that:

1. Selling only electricity from a stationary PEM fuel cell system can fail to produce a positive return on investment in regions with a low ratio of electricity price to natural gas price, even with costs projected for 10,000 unit production.

2. Thermal cogeneration can improve project economics, but may still fail to reach a target of 10% real, after-tax return on investment.

3. Producing hydrogen for fuel cell vehicles or other industrial uses during electricity off-peak periods can improve return on investment by 10 to 15 percentage points, assuming that all the hydrogen can be sold (requires about 44 FCVs per 50-kW fuel cell system with a building electrical capacity factor of 60%).

4. Alaska is the most favorable location for stationary fuel cell systems with respect to high electricity price to natural gas price ratio.

5. Project economics are improved dramatically if the fuel cell system operator can obtain industrial rates for natural gas instead of commercial rates. For example, the estimated real, after-tax return on investment increases from 5% selling hydrogen and electricity from a 50-kW fuel cell system in California with commercial natural gas rates up to 25% with industrial natural gas rates.

6. Project economics can also be improved by building an oversized reformer to support additional fuel cell vehicles or to supply hydrogen for industrial uses.

For small residential fuel cell systems, we do not project economic performance, even at the 10,000 unit production level. We find that:

1. Electricity prices would have to reach 44 cents/kWh in California before a 3.4 kW residential fuel cell system would return 10% on the investment based on avoided electricity costs alone. This poor performance is due to a combination of very low electrical capacity factor (24% to 27%) and high costs per kW for small systems.

2. Conversely, PEM fuel cell system costs would have to be reduced to only 6.7% (California) to 19.4% (Alaska) of the costs estimated here for 10,000 production quantities for the project to return 10%, again assuming only electricity displacement.

3. Adding hydrogen cogeneration reduces the need to cut costs, but still requires costs that are 7.6% to 41% of those estimated in this study for 10,000 unit production.

4. Selling electricity back to the grid during the off-peak hours is not a viable option.

Airport Ground Support Equipment

In this task we have evaluated the merits and costs of converting three types of airport ground support equipment (GSE) to run on hydrogen-powered fuel cell vehicles. For details of this analysis, see (Barbour 1998). We include the executive summary of this report below, followed by a summary of the cost comparisons between battery power and hydrogen-fuel cell power for the three types of GSE

Executive Summary of Airport Ground Support Equipment Analysis

Airport emissions have been garnering more attention recently, and the industry is looking for ways to reduce its contribution to local pollution and greenhouse gas emissions. Airport emissions are attributable to the aircraft themselves and the ground support equipment (GSE). Since there is limited potential to reduce aircraft emissions in the near-term, the focus of this recent attention has been on ground support equipment, even though GSE is only responsible for 2-6% of airport emissions (Corrales, 1997). Battery electric and natural gas have been the primary alternatives utilized in the industry to reduce emissions. Battery-powered vehicles have been primarily hampered by their range and recharging times, although improvements continue to be made in these areas. Natural gas vehicles have satisfactory performance, but achieve only limited emissions reductions.

Polymer Electrolyte Membrane (PEM) fuel cell technology offers an alternative method to achieve nearly zero emissions with equal performance. This study considered the feasibility of utilizing a fuel cell with or without a battery in three types of GSE: an airport shuttle bus, baggage tractor, and belt loader. This feasibility study was based on DOE goals of 0.5 kW/L and 0.5 kW/kg for the fuel cell system, Directed Technologies, Inc. cost models, standard emissions estimates, and knowledge of the GSE equipment in question.

The two alternatives considered in this study were the pure fuel cell vehicle (FCEV) and the range extender (RE). In the pure fuel cell option, the fuel cell was designed to meet maximum power requirements. The fuel cell in the range extender could be much smaller, meeting only the average power requirements, with the battery supplying peak power. For each case, the amount of hydrogen storage was chosen such that the vehicle is able to operate for a day0s operations before needing to refuel. A greater range could be provided by increasing the size of the hydrogen tank, within the space limitations of the vehicle.

In addition to demonstrating the technical feasibility of the concept, it is important to determine if the system will be cost competitive. Using previously derived cost estimation methods for fuel cells, hydrogen tanks, and batteries, the initial and mass production costs were calculated. While the fuel cell-powered vehicles are much more costly initially, the costs at mass production are projected to be below those of their battery-powered counterparts. Although the GSE market is relatively small, PEM fuel cell costs could be greatly reduced based on the mass production of PEM fuel cells used in all applications. The energy costs were based on hydrogen production from a factory-built steam methane reformer at $2/kg. This hydrogen cost was shown to be comparable to electricity used to charge battery-powered GSE at a rate of $0.09/kWh. The life cycle costs were calculated for each version utilizing capital costs, energy costs, and battery replacement costs, where applicable. The life cycle costs favored the fuel cell versions over the battery version, with the range extender having the lowest anticipated cost.

The greenhouse gas emissions and local air pollution contributions were used as a measure of the environmental benefits of fuel cell-powered GSE compared to diesel, natural gas, and battery electric. There is no clear advantage in terms of greenhouse gases for any of these power methods. By this measure, fuel cell vehicles using hydrogen derived from natural gas are almost equal to battery and diesel power. Fuel cell vehicles could virtually eliminate both local air pollution and greenhouse gas emissions if the hydrogen was produced from renewable energy sources. Local emissions were considered to include those from diesel and natural gas engines and from the steam methane reformer used to produce hydrogen. The power plants supplying electricity for charging, compression of H2, or reforming of H2 were considered to be outside the urban airshed. In the case of local pollutants emitted, however, fuel cell-powered GSE and battery GSE had 97-100% lower emissions than diesel or natural gas vehicles.

The important findings of this work are:

o Fuel cell-powered GSE are technically feasible. Based on DOE goals, a fuel cell or range extender system can be designed to use the existing space onboard the vehicles, achieving equal or greater power and range.

o Using cost estimates by Directed Technologies, Inc., it appears that this technology will become economically attractive as well, assuming that fuel cells are mass produced in large volume for other applications.

o Central refueling and public exposure highlight airports as a potential pathway for the introduction of commercial fuel cell technology. The GSE industry is, however, a limited market and will have difficulty achieving sufficient cost reduction in the near term (without mass production volume of fuel cells for other applications). Cost estimates show that of the proposed fuel cell power systems, only the range extender bus achieves cost equality with battery EV0s in the limited production case.

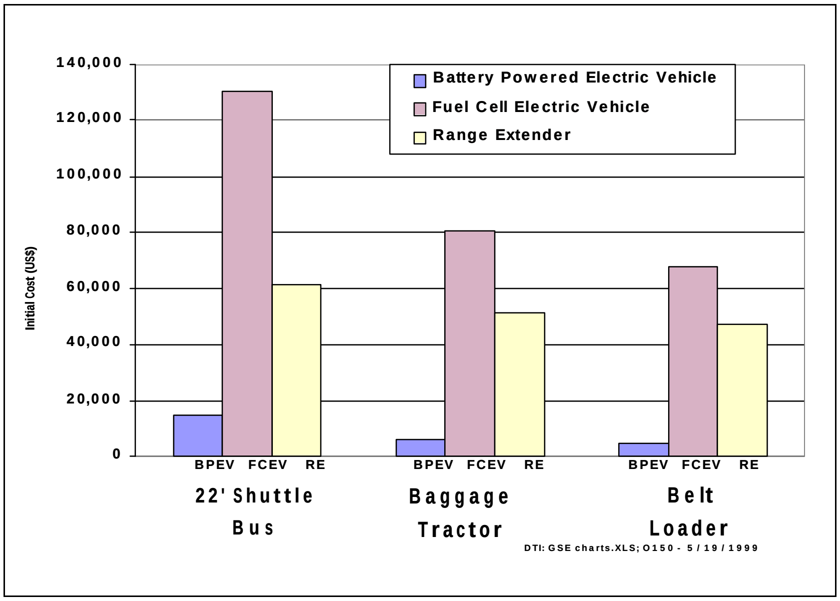
o FC-powered GSE offer the potential for increased performance. By definition, battery powered vehicles are heavy and have limited range. FC-powered GSE offer lower weight, longer range, and lower power requirements due to their lighter weight. Fuel cells may provide even more of an advantage in cold climates, where batteries have notoriously bad performance.

Y There is no distinct advantage of using the range extender (RE) concept compared to a pure fuel cell system in GSE. Both initial and mass production costs are slightly in favor of the range extender. However, the range extender will have a heavier power train and the fuel economy will be 20-35% lower due to the energy losses associated with charging and discharging the battery.

o Energy costs for FC-powered vehicles would be comparable to or better than battery or diesel powered GSE, assuming the use of a factory-built, stationary, steam methane reformer to produce hydrogen from natural gas at the airport.

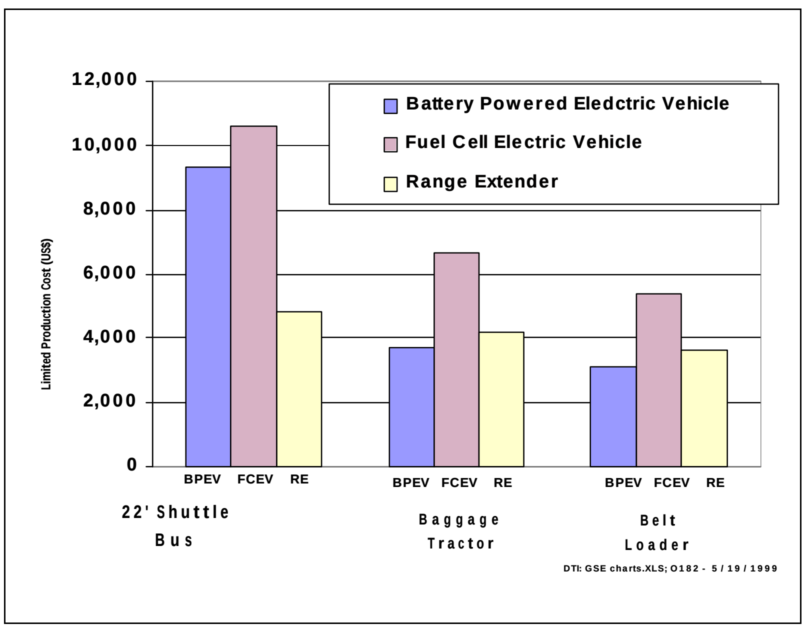
o Work is underway to demonstrate the feasibility of these fuel cell vehicle concepts. Bus demonstrations are well underway, and Tug Manufacturing has teamed with ZEVCO to work on an alkaline fuel cell baggage tractor. This joint venture has produced a prototype FC-powered M3 tractor and plans for production are tentatively set for late 2000. Unfortunately, this project seems inhibited by their reliance on alkaline fuel cell technology and Tug0s unwillingness to consider the hydrogen refueling issue .

Cost Comparisons of Battery- and Hydrogen-Powered Ground Support Equipment

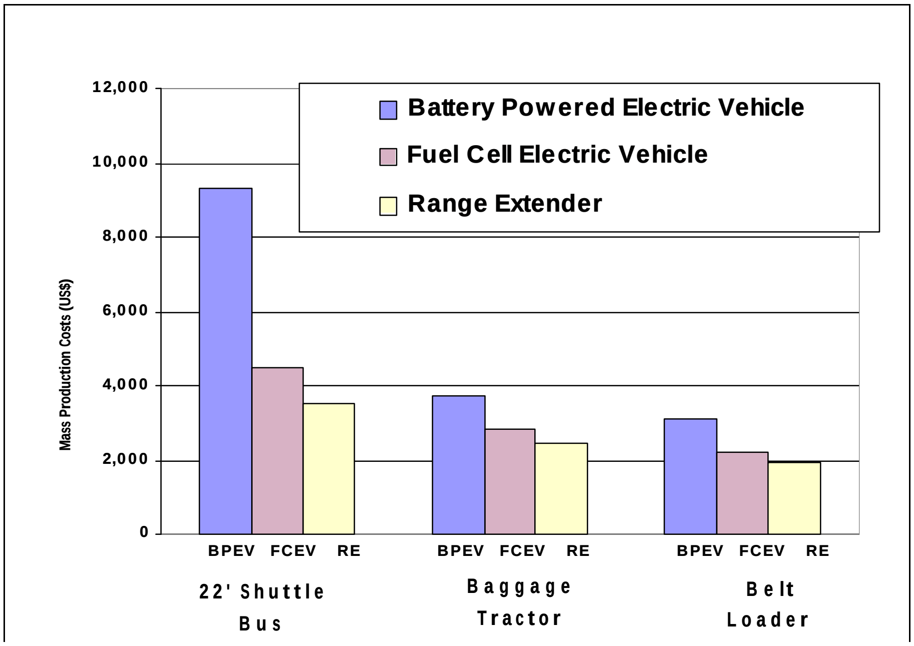


The cost of the power train for the three classes of GSE (22' shuttle bus, baggage tractor and belt loader) will depend on the production volume. Hydrogen-powered fuel cell vehicles will cost much more than battery-powered GSE equipment initially, as shown in Figure 1. We have also made estimates of the power system in production volumes of 10,000 units and 500,000 units as shown in the next two figures.

At the 10,000 production level, we are projecting that the power train for the range extender fuel cell shuttle bus will cost less than its battery counterpart. Fuel cell costs for the baggage tractor and belt loader range extender versions are also approaching the cost of a similar battery system at the 10,000 production level. For very large (500,000) production volume, both the pure fuel cell system and the range extender versions are less costly than a battery powered system for all three GSE vehicles, with the shuttle bus showing much better economics.



However, the likely sales volume of GSE alone will not lead to these types of production levels within a reasonable period of time. The total number of GSE in the United States is estimated at only 50,000 vehicles. Assuming a 10%/year turnover rate, and assuming a 10%to 20% market penetration in the beginning for fuel cell vehicles, then industry could only sell 500 to 1,000 vehicles per year.



It would take a decade to reach the 10,000 cumulative production level where the range extender shuttle bus would be competitive with battery-powered buses.

We conclude that other fuel cell vehicle markets will be needed to help reduce production costs and make hydrogen-powered fuel cell GSE equipment cost competitive with other clean-vehicle options.

Acknowledgments

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