Proceedings of the 1998 U.S. DOE Hydrogen Program Review

NREL/CP-570-25315

ECONOMIC AND TECHNICAL ANALYSIS OF DISTRIBUTED UTILITY BENEFITS FOR HYDROGEN REFUELING STATIONS

Joseph J. Iannucci
James M. Eyer
Susan A. Horgan
Distributed Utility Associates
Livermore, CA 94550
Susan M. Schoenung
Longitude 122 West, Inc.
Menlo Park, CA 94025

Abstract

This paper discusses the potential economic benefits of operating hydrogen refueling stations to supplying pressurized hydrogen for vehicles, and supplying distributed utility generation, transmission and distribution peaking needs to the utility.

The study determined under what circumstances using a hydrogen-fueled generator as a distributed utility generation source, co-located with the hydrogen refueling station components (electrolyzer and storage), would result in cost savings to the station owner, and hence lower hydrogen production costs.

Introduction and Background

Hydrogen refueling stations will represent a major capital investment in the hydrogen transportation infrastructure of the future. As a way to offset some of those costs and expand hydrogen markets, it is possible that a second use (an additional benefit) can be found for some of the on-site components if employed as part of a modern distributed electric utility. By dispatching a fuel cell on-peak with hydrogen created off-peak, appreciable benefits may be gained for the local utility. As those utility benefits are realized and shared with the owner of the hydrogen refueling station, the hydrogen transportation scenario becomes more economical. This project required selection of an operational hydrogen transportation/refueling scenario, station redesign to accommodate generation of power, determination of relevant economic figures of merit, and construction of an economic model with which to compare the system options.

Objective

The objective of this analysis was to determine if, for a re-optimized system configuration, this dual-use concept provides superior economic value over separate refueling and distributed utility systems. US market estimates were also created.

Approach

The hydrogen refueling/distributed utility station consists of either a regenerative fuel cell, or a fuel cell and electrolyzer, or a hydrogen-fueled engine, plus an inverter, a converter, a hydrogen storage system, transportation hydrogen refueling station components capable of handling an appropriate number of vehicles per hour, and a control system to coordinate operations.

The refueling station is connected to a utility source of electricity to power the electrolyzer to produce hydrogen. The refueling of cars results in a time-varying electrical demand for power to the dispensing systems and energy from the hydrogen storage system.

The combined hydrogen refueling/distributed utility system is designed to add value to the simple hydrogen refueling station by dispatching a hydrogen-fueled generator (fuel cell or engine) to meet critical local and system electrical needs of the local utility.

Using a stochastic approach to the range of avoided costs in U.S. utilities, an estimate was made for the range of hydrogen cost reductions possible across the U.S. and their likelihood of occurrence. Sensitivity to the on- and off-peak costs of electricity was also analyzed.

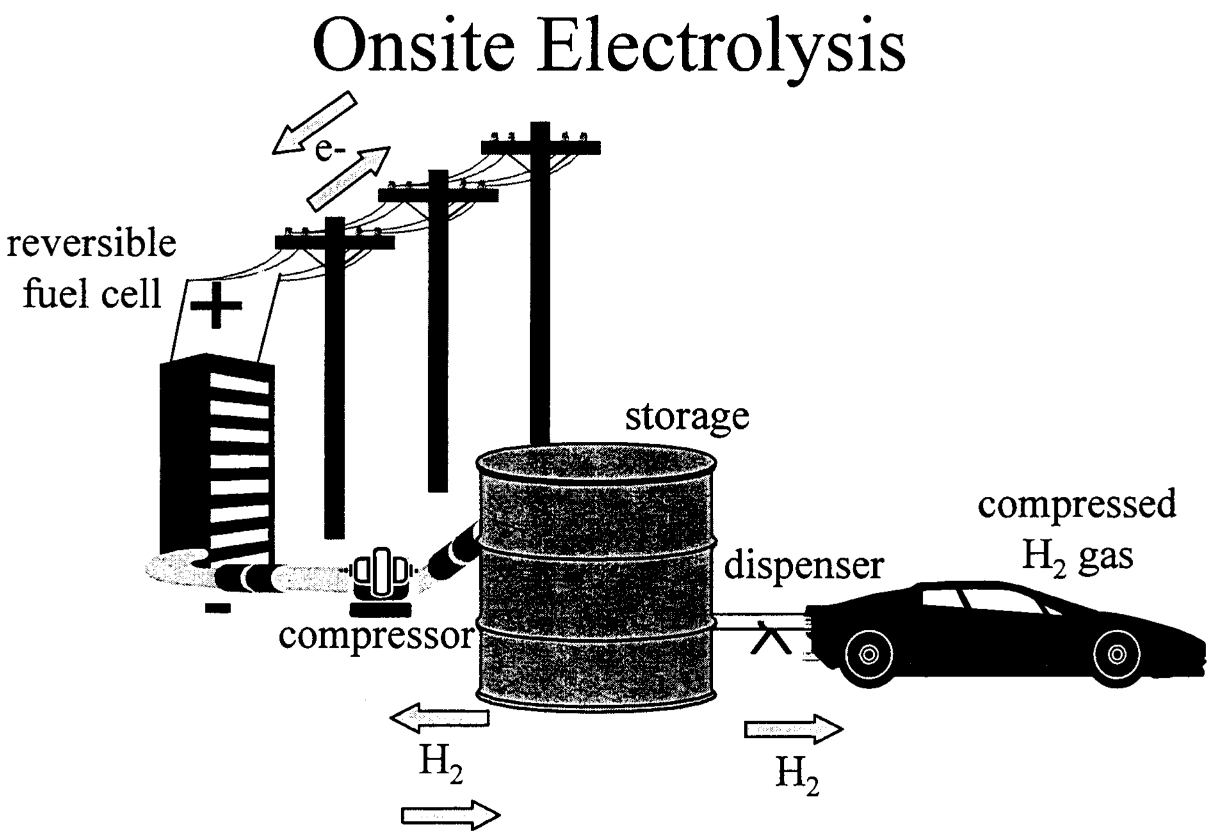
Distributed Utility/Refueling Station Assumptions

Figure 1 shows the components of the distributed utility/refueling station system. In this figure, a regenerative (or reversible) fuel cell is shown as the generation system.

Technology Assumptions

In this study, we begin with Princeton University's onsite-electrolysis base case (Ogden, 1995). Within the boundaries of the Princeton University study, we selected cases that appeared to have the best potential for substantial distributed utility benefits. A few parameters were adjusted to allow for reverse power flow, to better define the electrical and mechanical interfaces, and to calculate energy and maximum electrolysis load costs for the station owner.

Figure 1. System Components



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Our system consists of:

- Storage in pressurized cylinders; the pressure varies throughout the day from a minimum of 2000 psi to a maximum of 5000 psi.
- An advanced electrolysis process.
- Refueling station components, including a boost compressor that delivers hydrogen at 5000 psi.

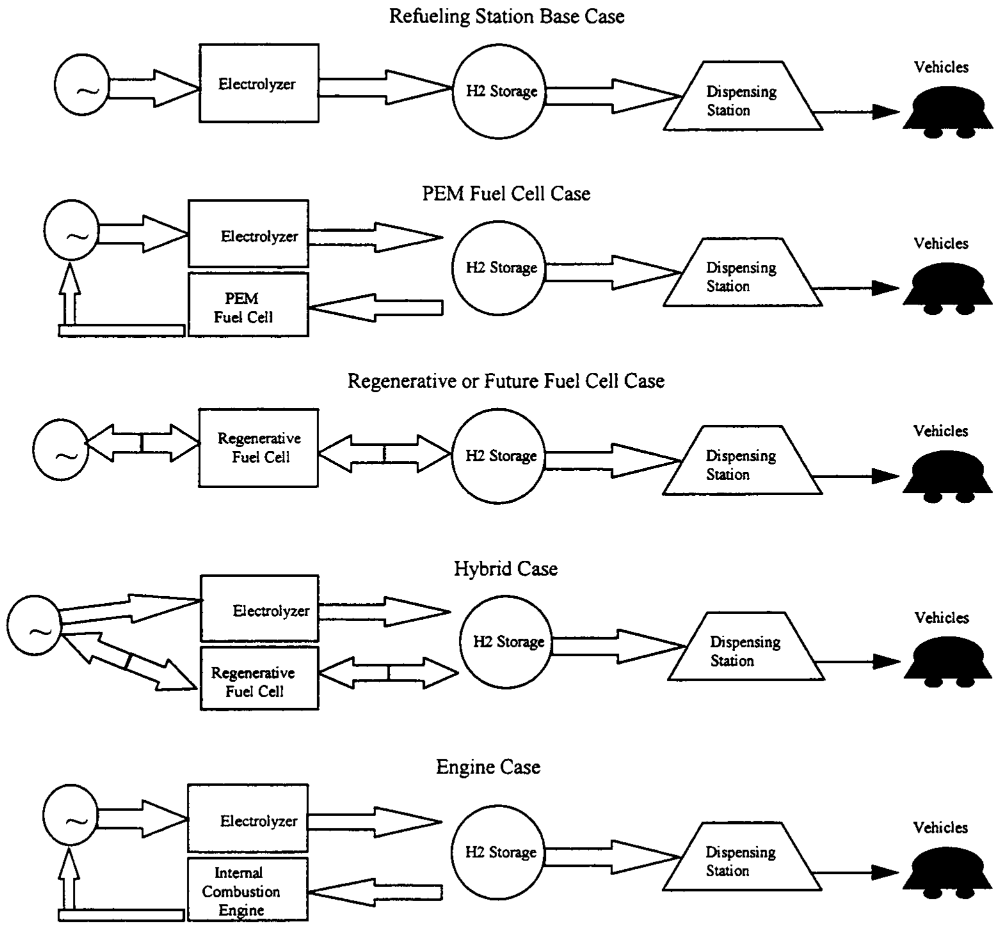
We assume that hydrogen production occurs 100% off-peak, during the 18 hours from 6PM to 12PM.

For the combined station to provide electricity for distributed utility functions, we added the following to the Princeton design:

- additional electrolysis capability to create the H_2 needed for fuel cell operation; additional storage for this hydrogen, and
- generation capability, either as a separate fuel cell unit, or in the form of a regenerative fuel cell, or some combination of the two; or in the form of a hydrogen-fuel combustion engine. All of these options are examined.

Layout flow charts for the cases considered in this study are shown in Figure 2.

Figure 2. Component Layouts



Analysis Assumptions

1. The number of vehicles served per day is either 200 or 400. In the Princeton studies, the number of vehicle ranges from 100 to 1000 per day (Ogden, et. al., 1995). The lower end of the Princeton University range was used to increase the potential benefits of the old dispatch. Above 400 cars/day, the utility would likely build a dedicated substation for the refueling station, making distributed utility and its value nearly irrelevant.
2. Refueling availability is undisturbed by the electrolysis or distributed utility function; i.e., the station is open 24 hours per day. We assumed station owners and clients would not adjust their lives or economics for the sake of distributed utility benefits increases, e.g. by stopping all refueling or boost compression during daily peak utility demand hours.
3. All hydrogen to meet the distributed utility function and refueling need is produced off-peak, during the 18 hours from 6 PM to 12 noon. This minimizes the cost of electricity use, minimizes electrolyzer sizes, and minimizes load factors.
4. Additional storage is the same type as the base case (pressurized cylinders) at the same $/scf.

5. Electricity generation (i.e. fuel cell dispatch) always occurs at the time of optimum utility benefit. The major analytical work of this project involves optimizing the benefit versus cost of adding more hydrogen and generation components for distributed utility operation.
6. This study's base case has a distributed utility operating 1 hr/day and approximately sized at the same size as the electrolyzer, i.e. 1.4 MW for 200 cars, and 2.8 MW for 400 cars.
7. The daily schedule of power flows and stored hydrogen energy is charging and discharging during peak and off-peak periods, with a regularly spaced traffic of cars throughout the day. If all the cars arrived during the peak period when the electrolyzer does not operate, the stored hydrogen would decrease to 40% full. This is the minimum needed to maintain 2000 psi in the storage cylinders.

Hydrogen System Cost and Performance Analysis

The components of the system are:

- electrolyzer
- storage cylinders
- storage compressors
- fuel cell or combustion engine plus power conditioning components
- station components, including boost compressor, dispensers, and fixed infrastructure

The assumed capital cost, operating cost, lifetime and efficiency of these components are listed in Table 1. For those components which are the same as the Princeton study, the cost assumptions are identical (Ogden, et. al., 1995).

Two types of PEM fuel cells were included in the analysis: a simple hydrogen-fueled PEM, and a regenerative PEM. The regenerative PEM includes the electrolyzer function when operated in reverse. This makes it more expensive because the catalyst loading must be higher to operate in the higher temperature electrolysis mode (Thomas, 1995). It is possible that future regenerative fuel cells may not need the additional catalyst (Mitlitsky, 1998) and could cost the same as a simple PEM.

An internal combustion engine was also considered for this application. Diesel engine manufacturers have indicated that hydrogen combustion could be accomplished with little modification and at reasonable capital cost (Keller, 1998 and NREL, 1997). Other operating costs, in addition to O&M, are labor costs of $131, 400/yr and electricity costs at 2¢/ kWh off-peak and 7¢/kWh on-peak. These are identical to the Princeton study assumptions. An identical capital charge rate of 15% is also assumed. This is consistent with private (rather than utility) ownership of the station.

Energy and Power Requirements

The energy required per day and the peak power to the system depend on:

- the number of vehicles served per day
- the number of dispensers operating at the station (assumed to be four)

Table 1. Technology Data

Component	Capital Cost	O&M Cost	Efficiency or Energy required	Lifetime
Advanced electrolyzer	300 $/kW H2 out	4% of cap cost/yr	η=0.8	20 yrs
Storage cylinders	1.1 $/scf	100 $/yr/cylinder		20 yrs
Storage compressor	2000 $/kW	$3000/yr/unit (2 units)	(.6225 kW/car × # cars/day × 18 hrs/day) +DU	10 yrs
PEM fuel cell	500 $/kW	4% of cap cost/yr	η=0.60	20 yrs
Regenerative fuel cell	1000 $/kW	4% of cap cost/yr	η=0.60 in gen mode	20 yrs
Future regenerative fuel cell	500 $/kW	4% of cap cost/yr	η=0.60 in gen mode	20 yrs
Internal combustion engine	350 $/kW	4$ of cap cost/ yr	η=0.40	20 yrs
Fixed components	$277,100 (= 4 dispensers + boost compressor)	4% of cap cost/yr	1.875 kWh/car × # cars/day	10 yrs

- the power level of the distributed resource (approximately same order of magnitude as electrolyzer, so as to not adversely affect distribution service rating)

The distributed utility rating of 1.4 MW equals the electrolyzer rating for the refueling function alone for 200 cars per day. The 2.8 MW rating corresponds to the 400 cars per day.

Capital Cost Trade Study

To obtain a set of capital costs for the Benefit/Cost study, a range of distributed utility types, sizes and operating times were considered for two service levels, 200 cars day and 400 cars/day.

Four relatively near-term fuel cell technologies (PEM, RFC, hybrid, and IC Engine) and one long-term future regenerative fuel cell option (future RFC) were compared to one another.

- The PEM design has separate electrolyzer and fuel cell components, the electrolyzer sized to meet the hydrogen supply needs and the fuel cell sized to provide the desired distributed utility output.
- The RFC design has a single electrolyzer/fuel cell unit, sized to meet the hydrogen supply needs; this makes the fuel cell capability oversized to provide the desired distributed utility output.

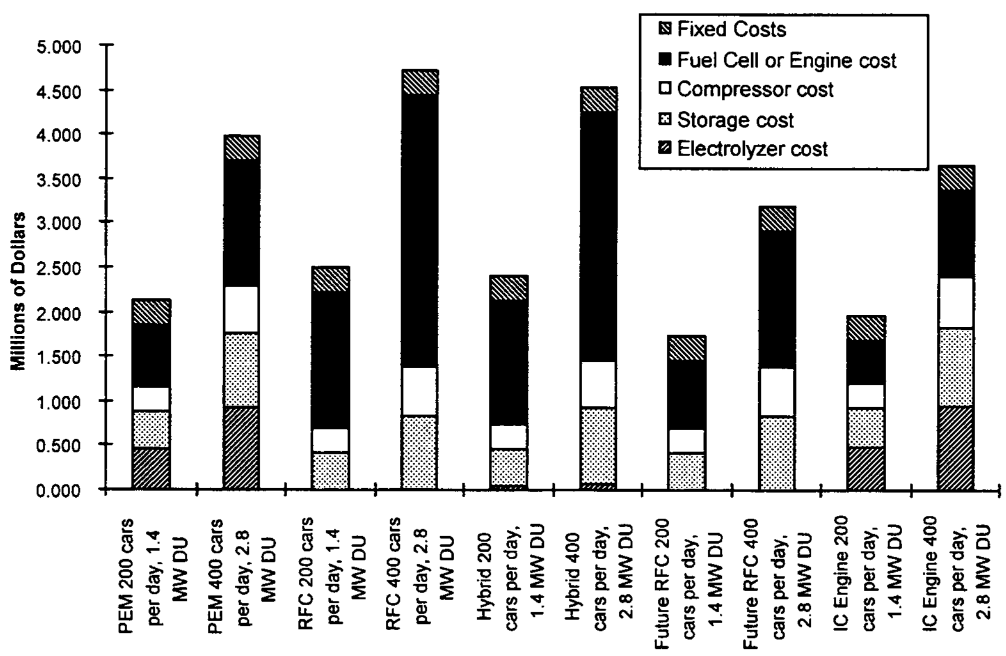
- The hybrid design has a small RFC sized to provide the desired distributed utility output and a small portion of the hydrogen supply needs, plus a separate electrolyzer component sized to meet the remainder of the hydrogen supply needs. This is a cost-efficient design since it uses the more expensive reversible component precisely for the distributed utility aspects only.
- The future RFC design has a single electrolyzer/fuel cell unit, sized to meet the hydrogen supply needs; this makes the fuel cell capability oversized to provide the desired distributed utility output.
- The engine system assumes mass produced diesel generator technology suitable for hydrogen combustion; the separate electrolyzer is sized to meet the hydrogen supply needs and the fuel cell sized to provide the desired distributed utility output.

Note that the electrolysis rating for the combined refueling/generation station will always be somewhat larger than for the refueling station because the electrolyzer must generate enough hydrogen for both the generation and refueling functions.

The least-cost approach, under most conditions and for the assumed costs, appears to be the future regenerative fuel cell. The lowest cost system does not necessarily yield the highest net benefits, however.

For the 200 cars and 400 cars 1 hr/day cases, Figure 3 shows the component costs for the

Figure 3. Capital Cost Components for all Technologies (Distributed Utility operates 1 hr per day)



different technologies. Not unexpectedly, the generator (fuel cell or engine) cost is the largest single component. The fixed costs are the same for both 200 and 400 car cases because a 4-dispenser station is assumed for both.

Utility System Benefits

Economic Analysis Approach

The metric chosen for the economic optimization of the combined hydrogen refueling station/distributed utility plant is the delivered cost of hydrogen to the vehicles. If the distributed utility dispatch capability can more than pay for itself, the cost of delivered hydrogen should be reduced. The owner may choose to pass any savings along to the clients of the station, or may use them for higher profitability.

The station is considered to be owned by a private party, purchasing electricity from the local utility at prevailing rates. Most of the purchased electricity is used to power the electrolyzer (or equivalently the regenerative fuel cell), but additional power is needed for the storage compressor during electrolysis, for the boost compressor during fueling, and for other miscellaneous on-site loads.

In an effort to reduce his operating costs or increase the station's cash flow, the owner is considering dispatching an on-site fuel cell on demand for the utility. The owner is planning on receiving some or all of the benefits the utility gains by this dispatch. The fraction of the utility savings he receives is the subject of a negotiation with the local utility.

Operational Issues

Although each station's location and operation would be slightly different, we have assumed that the utility calls everyday in mid-afternoon to request dispatch of the fuel cell to meet system and transmission and distribution peaking needs. This is usually the peak of a utility's demand and costs and the most stressful time for the refueling station owner to dispatch the unit. We assume that the owner responds by dispatching the unit for the specified length of time as directed by the utility. An imperfect reliability is included in the economic analysis by decreasing the utility benefits by the presumed lack of availability of the fuel cell, 5%.

In addition, the full capacity of the distributed utility unit cannot be assured during the utility-requested dispatch time due to the need to continue serving calls and operating the boost compressor. Again the benefits of the generation, transmission and distribution capacities are reduced by the peak boost compressor demand. An alternative operational approach could have been to close the station during the utility's peak demand period, but this was rejected as being detrimental to station business. Note that the station owner does not operate the electrolyzer at all during the peak rate period of noon to six PM, to avoid high demand or energy charges.

We have also considered three durations of dispatch (one-half, one and two hours) which should cover most utility peak width situations. The half hour dispatch case is highly beneficial to a distributed utility owner since almost no fuel (in this case fairly expensive hydrogen) is needed to obtain the same capacity benefits as a longer dispatch period. The energy benefits are not very valuable for low-capacity-factor distributed utility units. The one hour dispatch is probably the most important case since system and especially local peaks are not often very broad. Two hours every day is conservative. If weekend and off season dispatch could be avoided, it is possible that the economics could be improved marginally although the capital costs of the fuel cells, extra compressor and storage capacities remain sunk. The results of the modeling are independent of the actual time that the utility calls for load relief, but our assumption is that it comes at the most inopportune time in the mid-afternoon.

Economic Analysis with the Distributed Utility Units

Of course, the capital costs for cases with distributed utility components are higher than the base case due to the need for the fuel cell (in all cases except the future regenerative fuel cell) and for more hydrogen storage capacity in all cases. Additionally the need for more hydrogen for dispatch of the fuel cell means a larger compressor, more cushion hydrogen gas, and more electricity for the electrolyzer and storage compressor.

In the cases with distributed utility components included, the distributed utility benefits are subtracted from the annual system costs to yield a net annual cost including these benefits. Depending on the magnitude of the distributed utility benefits, they may or may not pay for the additional distributed utility dispatch hardware. This is the subject of this study.

Utility avoided costs consist of both central and distributed components, assuming utility type economics for their avoided costs. The central benefits included in this study are central capacity (the ability to avoid the purchase of additional peaking capacity) and energy (the ability to avoid fuel purchases). If a utility can dispatch a distributed generation plant it can benefit by this avoided or deferred investment in capacity. If the fuel is not paid for by the utility this is an added benefit. The magnitude of these benefits depends upon whether the utility currently needs more peaking capability and the type and cost of fuel, and the utility plantís heatrate on the margin. Central capacity benefits can be as low as zero or as high as 50 $/kW-yr; the units of $/kW-yr are used as a way to annualize the carrying cost of owning or contracting for peaking capacity; the same units are used for transmission and distribution avoided costs. The fuel used by the power plants on the margin can range up to five cents per kWh, but rarely would fall below three cents per kWh. This unit is converted to $/kW-yr by multiplying by the appropriate hours per year of distributed utility unit operation.

The distributed benefits included are the avoided transmission and distribution investments for wires and transformers by the local distribution company and the value of improved reliability to the local customers. Similar to the central capacity benefits, if local load can be served by local generation, wires investments can be reduced, saving the utility money. Transmission and distribution avoided costs (benefits are rarely zero since wires capacity expansions are never done without need being proven first) can be as high as 20 $/kW-yr. and 70 $/kW-yr., respectively. Improved customer reliability is not an immediate, direct bottom-line benefit to the utility, but is increasingly important to utilities as they strive for customer loyalty as deregulation unfolds. Reliability benefits can be as low as zero and can range up to many dollars per lost kWh. We have used 25 $/kW-yr.

If a distributed utility unit is perfectly dependable, all of these benefits (avoided costs) can theoretically be earned by the owner of the unit. The owner of the distributed utility unit of course must pay for the fuel used, the carrying costs of the capital and the O&M costs.

In order to evaluate a range of utility situations the generation, transmission and distribution, energy and reliability avoided costs were evaluated for bins each representing one fifth of the U.S. Thus the costs range from the lowest avoided costs in the U.S. up to the highest (best for distributed utility) 20% in the country. In this way the broad range of values in the U.S. could be examined without site-specific information.

The utility avoided costs are derived from many sources, such as EIA annual summaries of utility capital investments, FERC Form 1, GRI projections of future fuel costs, etc. All utility avoided costs are annualized assuming a typical amortization of 30 years for generation, transmission and distribution investments

Cost of Hydrogen Results

Overview

A wide range of technologies, sizes, dispatch durations and numbers of cars refueled per day were examined to determine the overall viability of using distributed utility dispatch at hydrogen refueling stations.

The majority of the analysis was done using nominal or median values for the distributed utility benefits which these hydrogen refueling station installations could earn; one sensitivity section examines a range of avoided costs and the impact of sharing the benefits between the utility and the station owner. Another sensitivity section considers the impact of changing on-peak and off-peak electricity costs from the original Princeton values.

Base Case Results

For the 200 car per day base case (refueling station only with no distributed resource), hydrogen could be delivered to the clients for 18.33 $/GJ. For the 400 car per day capability the costs dropped to 15.55 $/GJ. The capital cost of the larger capability station is only 79% more than the smaller version, and since the throughput is doubled the overall economics are approximately twenty percent superior. This substantial superiority of the higher capacity station is reflected in all of the results of the study, whether including distributed utility units or not. The improvement with number of cars served per day agrees with the Princeton Study.

These two base cases are used for comparison to the distributed utility economics to evaluate the relative value of adding dispatch capability.

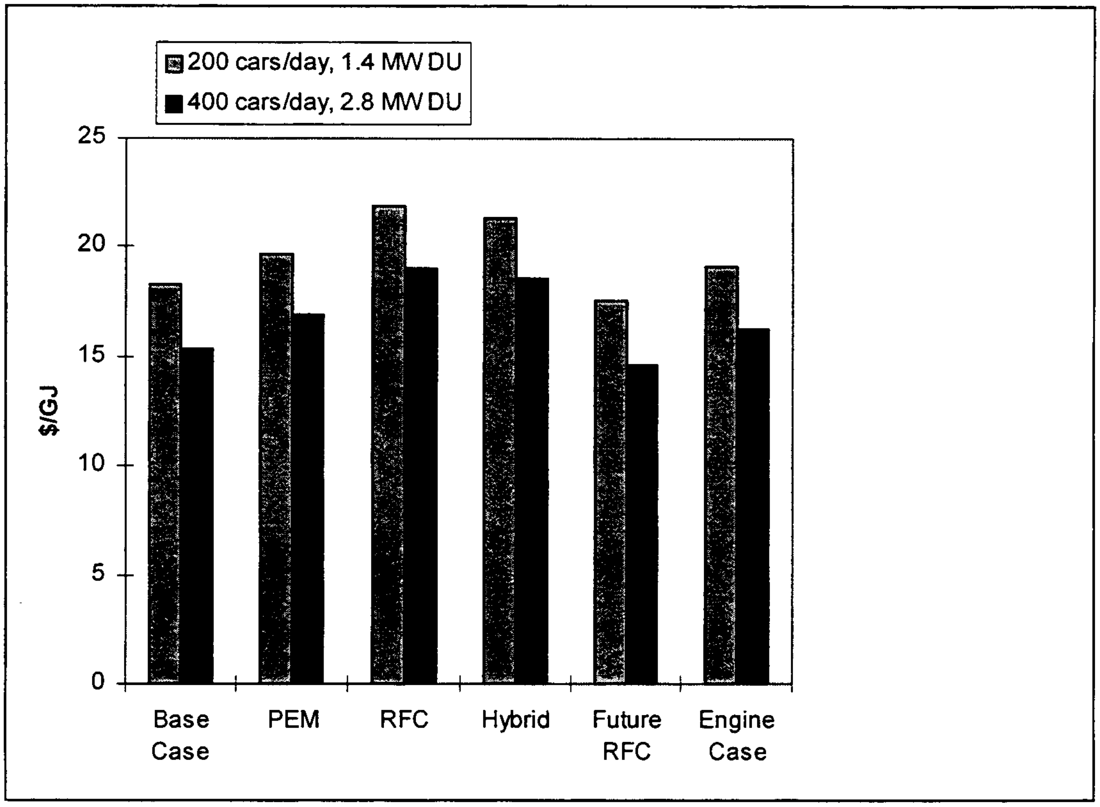
Overview of Distributed Utility Results Using National Average Data

Technology Ranking

In a general sense the future RFC has the best (lowest) cost of hydrogen production followed by the engine, the PEM, the HYB and least desirable is the RFC. Using any of the near-term joint refueling/distributed utility designs to reduce the cost of hydrogen does not appear to be likely, but it is very close to making sense for the PEM.

The long-term future RFC design is ideal for distributed utility applications at refueling stations, handily beating the base case at both car handling sizes. The future RFC design, should it ever be realized, is ideal for such a refueling station application since the hardware is used nearly continuously, whether electrolyzing off-peak or discharging for an hour or so per day.

Figure 4. Cost of Hydrogen for 1 hr/day Distributed Utility Cases with Median Benefits



Sensitivity to the Dispatch Rating of the Distributed Utility Units

The rating of the distributed utility unit provides a much more interesting story. The PEM and HYB cases become less attractive as the distributed utility unit is dispatched at higher and higher power. Apparently as more power is demanded the additional capital costs for the fuel cell portions are not outweighed by the additional distributed utility benefits. Thus the economics are pushing the size toward zero fuel cell size.

However in the single component designs (RFC and future RFC) the fuel cell function is underutilized at low power, so that requesting that it operate at higher power levels reduces the net cost of hydrogen from the station. This is not an unlimited capability however since the electrolyzer side has capabilities at 1.6 MW and 3.2 MW for the 200 and 400 car per day respectively, only slightly higher than the dispatch rating maximum studied here. Thus the most reasonable size to consider for distributed utility applications of refueling stations for single component designs is the electrolyzer forward rating, approximately the same as the high end of the dispatch size selected herein.

Sensitivity to Utility Benefits Using a Distribution of Avoided Costs

The near-term applications potential for distributed utility operation of fuel cells in conjunction with refueling stations looked near enough to economic viability that a closer look seemed reasonable. Perhaps the use of a national average for the utility benefits of distributed utility dispatch was hiding the application of these units in some fraction of the upper end of utility avoided costs.

We selected the PEM case for further in-depth analysis. We added two features to the analysis to provide more insight into the potential for this application:

- a distribution of utility avoided costs into five bins, and
- a parameter to show the amount of savings which a utility and a distributed utility owner might negotiate

The results for the five bins are shown in Figure 4 for both the 200 car/day case and the 400 car/day case.

Figure 5. Cost of Hydrogen vs. Hours/day of Operation 400 cars/day, PEM

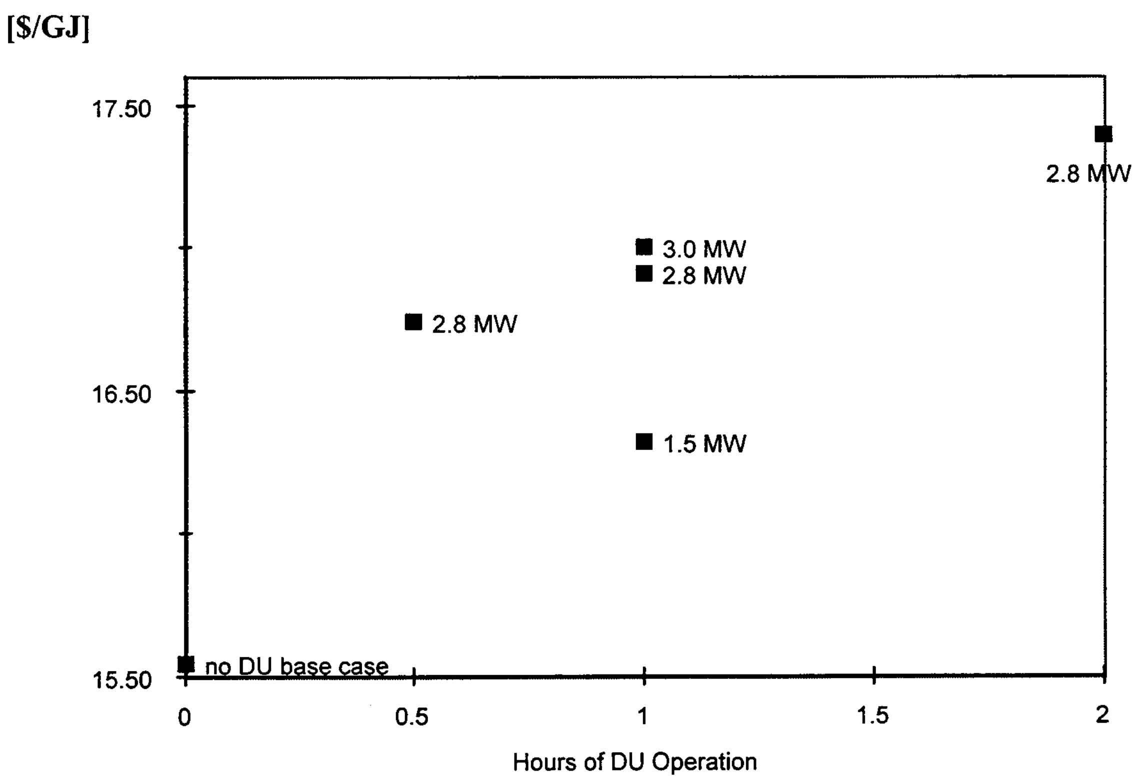


Figure 6. Cost of Hydrogen vs. Hours/day of Operation 400 cars/day, Future RFC

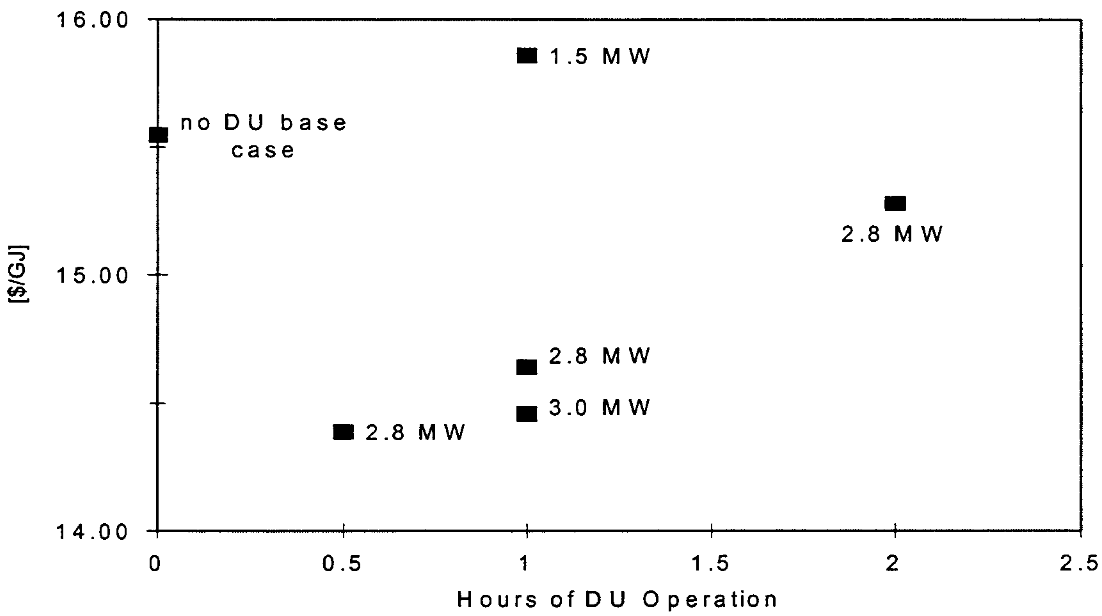
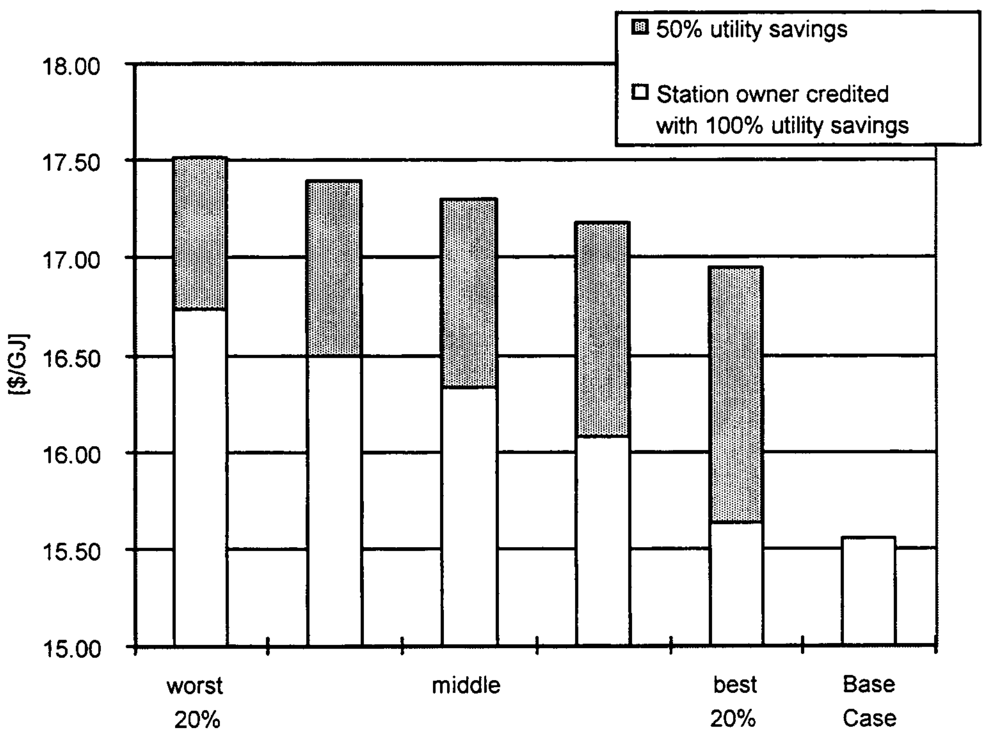


Figure 7. Cost of Hydrogen vs. Range of Utility Benefits for 1 hr/day, PEM, 400 cars/day



Studying the Sensitivity to Electricity Costs

The baseline electricity costs (2 cents per kWh off-peak and 7 cents per kWh on-peak), while consistent with the Princeton refueling station economics study, may not be representative of a large portion of the US. These original electricity costs are more representative of electricity production costs than the price a commercial customer would pay for electricity. Further, electricity costs have risen somewhat in the last few years in parts of the country and the relationship between peak and off-peak is not the same everywhere.

To study the sensitivity to this important variable in estimating the cost of electrolysis, we have used an alternative set of higher costs to purchase electricity:

- 4 cents per kWh off-peak and
- 8 cents per kWh on-peak.

The results are shown in Figure 8. Even though the hydrogen production costs rise by roughly one-third with more expensive electricity, the technology ranking results are not impacted to first order by the use of higher electricity costs, since the base case hydrogen costs also rise proportionately. Slight relative advantage will be found for the more efficient fuel cells compared to the less efficient hydrogen engine technology since the electricity to make the extra hydrogen for distributed utility dispatch has become more costly.

A more subtle issue is whether the electrolyzer should still operate eighteen hours per day if the off-peak costs average as high 4 cents per kWh.

Figure 9 shows the components of delivered hydrogen cost ($/GJ) for several cases at both the baseline and alternative (higher) electricity costs. The figure indicates that electricity and capital are the major cost elements. The final cost of hydrogen is very sensitive to off-peak electricity costs. The size of the DU benefits is also shown for these cases. These values are negative since they subtract from the cost components in computing the final cost of hydrogen.

Discussion

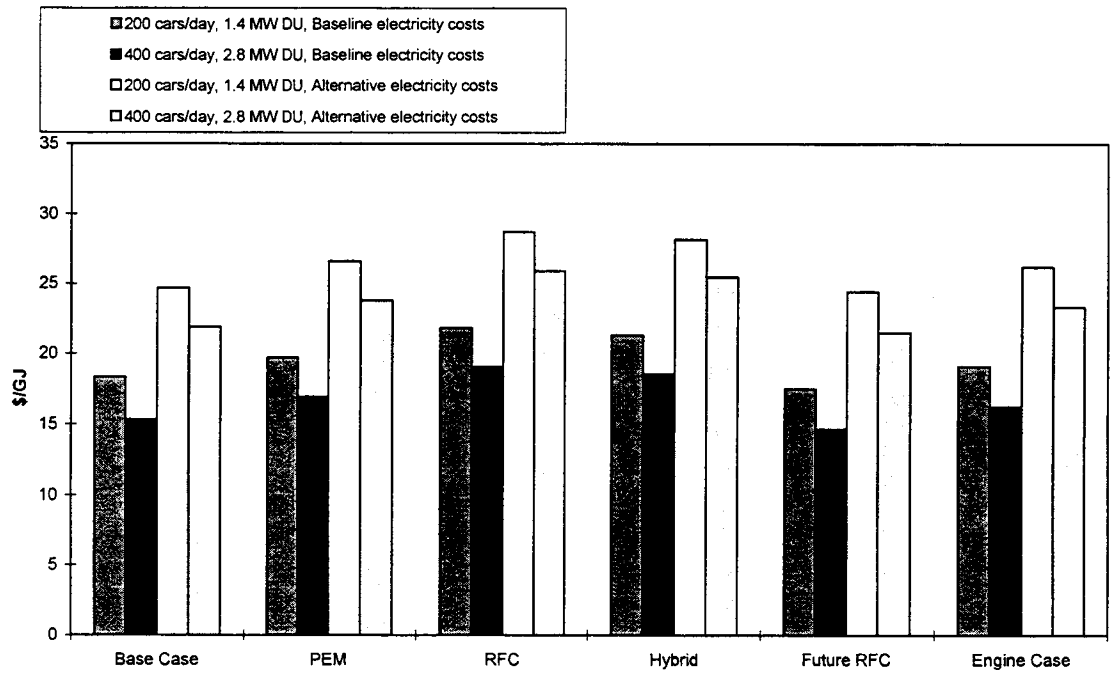
As utilities become more comfortable negotiating such shared distributed utility savings arrangements with owners of distributed utility plants, the near-term PEM or hydrogen engine technical options should be re-evaluated for economic viability.

For example, the top 20% bin of utility avoided costs still represents an average of almost 200,000 MW of installed capacity in the US; at the upper end of that bin can be large markets and profitable locations which could be quite viable if the utility is motivated to share the distributed benefits.

Even small reductions in some of the technology costs or improvements in performance could swing the equation in favor of PEM or hydrogen engine distributed utility units at refueling stations.

A decision to slow down or eliminate refueling during the utility peak hour (to eliminate the parasitic load of the boost pump), would have made the PEM or hydrogen engine attractive.

Figure 8. Cost of Hydrogen for 1 hr/day Distributed Utility Cases with Median Benefits (Baseline Electricity Costs: 2¢/kWh off-peak, 7¢/kWh on-peak; Alternative Electricity Costs: 4¢/kWh off-peak, 8¢/kWh on-peak)

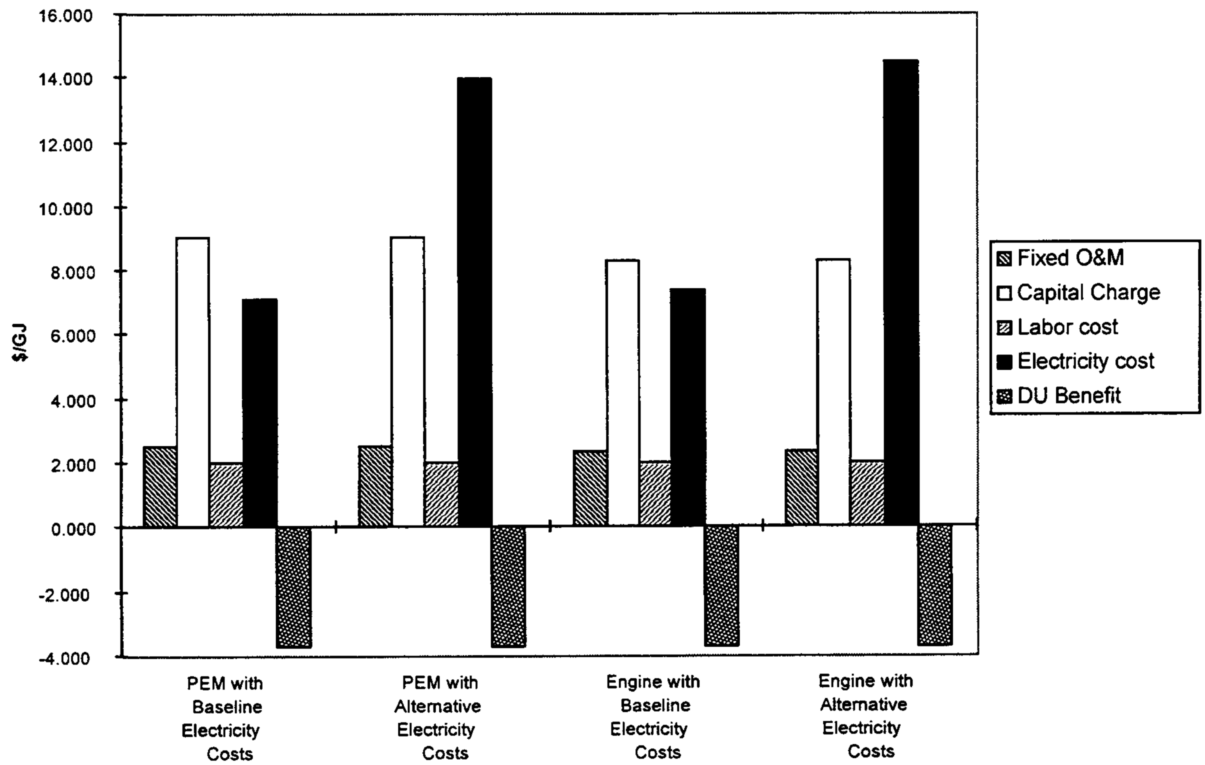


Alternatively, allowing the pressure in the cushion gas to drop below 40% of maximum (which would only occur if all 200 or 400 vehicles/day were fueled during the peak period with no electrolyzer operating) might have been cost effective. The lost distributed utility benefits would need to be traded off with an occasional excessive power drain to get storage pressure back within operating range once the utility's daily peak hour is over.

Another major factor which could make these hydrogen engine or PEM distributed utility units compellingly cost-effective would be even small incentives or green power credits for their operation. A one cent per kWh credit for hydrogen derived output would make DU at a refueling station much more attractive economically. Likewise, a strategy in which the DU plants are not scheduled for dispatch on weekends and during the off-peak season could provide some savings in electrolysis costs.

The hydrogen fueled engine results deserve discussion for two reasons: 1) the engine could be the nearest term technology option, and 2) its cost and performance assumptions depend on different factors than the other electric generation technologies. All of the generation technology

Figure 9. Components of Cost of Hydrogen for 1 hr/day Distributed Utility Cases with Median Benefits (Baseline Electricity Costs: 2¢/kWh off-peak, 7¢/kWh on-peak; Alternative Electricity Costs: 4¢/kWh off-peak, 8¢/kWh on-peak)



cost and performance estimates used in this study anticipate technical success and mass production levels (for utility or transportation applications). The hydrogen fueled engine costs may be the most sensitive to transportation market mass-production levels. The fuel cells may reach mass production via utility applications at prices higher than the transportation market sector can likely support. However the simplicity of the hydrogen engine approach may be very attractive to the transportation industry. The hydrogen engine distributed utility generator might have looked even more promising if the station had been designed to service vehicles with hydride storage or if hydride storage had been used for the bulk on-site storage.

The future RFC seems to be ideally suited to the distributed utility application at refueling stations. This technology should studied carefully and the economics reexamined as it comes closer to the marketplace.

Utilities should be alerted to the potential for use of hydrogen refueling technologies as assets in their electric systems. As utilities become more familiar with hydrogen as a fuel and with the distributed utility concept in general this option will gain in importance.

The higher electricity cost sensitivity suggests that there might be a preferred operational strategy. A more detailed analysis might consider dispatch of the electrolyzer against real time of day rates, varying seasonally and daily; more detailed vehicle refueling patterns would need to be included also. The results of such a study might recommend using the electrolyzer only during super-off-peak times, perhaps less than twelve hours per day, when commercial rates can approach 2 cents per kWh. Of course, more electrolyzer capacity would be needed and its capacity factor would diminish, but this might be economically preferred. The analysis of all of these optimum electrolyzer dispatch options was beyond the scope of the study.

Acknowledgments

The authors would like to thank Dr. Joan Ogden of Princeton University for her helpful insights, input and review. Dr. Ogden gave generously of her time and expertise.

The authors appreciate the modeling and computational support of Mr. Peter Sigmund.

The authors also acknowledge useful conversations with Mr. Fred Mitilsky of Lawrence Livermore National Laboratory, Dr. Sandy Thomas of Directed Technologies, Inc., Dr. Jay Keller of Sandia National Laboratories, and Mr. Phil DiPietro of Energetics, Inc.

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