Proceedings of the 1999 U.S DOE Hydrogen Program Review
NREL/CP-570-26938

Economic Market Potential Evaluation for Hydrogen Fueled Distributed Generation and Storage

Spring 1999

Prepared by:

Joe Iannucci, Jim Eyer and Susan Horgan
Distributed Utility Associates

Susan Schoenung
Longitude 122 West, Inc.

I. Executive Summary

Background

Hydrogen has been proposed as a clean fuel for the future, both in vehicle and stationary power (electric utility) applications. Two conversion technologies - fuel cells and internal combustion engines - can make use of hydrogen fuel in the near term. In the electric utility market, hydrogen-fueled technologies are likely to be used in distributed generation applications, the fastest-growing segment of the generation market. Significant market penetration of hydrogen-fueled generation would have a positive impact on national air emissions.

Project Scope

The objective of this study is to evaluate the potential market penetration of hydrogen-fueled distributed generation and storage, and the resulting impacts on total air emissions from all generation. Market potential is determined by comparing the total cost to meet new load growth with distributed generation against the cost of the traditional utility capital investment that would be required. Hydrogen-fueled distributed generation technologies are compared with fossil-fueled technologies, and the impacts on the study results of considering environmental penalties for air emissions are also examined. The market model is used to evaluate results in the year 2002, both on a national basis, and for the Southwest US region specifically.

Six peaking and six baseload distributed generation technologies were chosen, based on their existing economic viability or their likely feasibility in the near future, and on their ability to use either natural gas or hydrogen as fuel. The DUVal model was used to estimate the likely market penetration of these technologies from a utility perspective, based on a comparison between the annualized cost to a utility to own and operate a distributed generation technology with the possible annualized benefits from the technology. The net change in total air emissions can then be estimated from the mix of central and distributed generation that results.-

Results

Hydrogen-fueled generator technologies, operating as peaking resources, have substantial market potential, ranging from about 33% to 91% of potential market share, compared to a range of about 45% - 98% for conventional natural gas-fired distributed generators. When environmental penalties are applied, all hydrogen generators except one improve market share, resulting in a range of 44% to 98%, compared to 52% - 99% for natural gas.

In baseload applications, very few technologies have significant market potential unless environmental externalities are considered; in the latter case, hydrogen-fueled turbines and fuel cells have significant potential, while all conventional generators are cost-effective for all new load.

In the Southwest US case, hydrogen-fueled distributed generation is slightly less cost-effective in peaking applications, in general, than in the US as a whole, but still is very competitive. As base load resources, hydrogen-fueled distributed generation is not cost-effective at all (as in the national case) unless environmental penalties are considered, in which case their market potential is similar to the US case, with the Advanced Turbine System and the Phosphoric Acid fuel cell having significantly more positive results.

Conclusions

As peaking resources, distributed generation has substantial potential for use by utilities, whether or not environmental penalties are applied. Even generators with high emissions can be cost-effective, because of the few hours of operation involved, and also because of low initial capital cost (e.g., Diesel engines and combustion turbines). If hydrogen is the fuel of choice, the higher cost to supply this fuel negatively impacts the market potential of peaking resources, but not to a great extent: hydrogen-fueled generators will still be the lower-cost option relative to the grid in a significant percentage of cases.

Distributed generation does not appear to have significant market potential for baseload applications, absent environmental penalties being applied; the existing central generation fleet, with its relatively low costs of production and highly depreciated capital investment, is difficult to beat. However, if environmental penalties are applied, some hydrogen-fueled generators are competitive for substantial portions of the market, particularly fuel cells, as are all fossil-fired distributed generators.

II. Introduction

Background

Hydrogen has been proposed as a clean fuel for the &m.n-e, both in vehicle and stationary power (electric utility) applications. Two conversion technologies - fuel cells and internal combustion engines can make use of hydrogen fuel in near term systems. In the electric utility market, hydrogen-fueled technologies are most likely to be used in "distributed utility" applications, the fastest-growing market segment for small to moderate sized generation technologies, If hydrogen-fueled generators can move into this market, it represents a dual opportunity: hydrogen can become a main-stream fuel, and the acceptance of fuel cells and clean-burning engines in the power market can be accelerated. Additionally, significant market penetration of hydrogen-fueled generation would have a positive impact on national air emissions.

The concept of the Distributed Utility implies the use of relatively small, modular power technologies that provide power and/or energy when and where needed ("distributed resources"), rather than the traditional large, central station utility power plants. By definition, distributed resources are connected to the electric utility's distribution system, but possibly off-grid as well. The term "distributed resources" is synonymous with "distributed generation and storage" and may comprise one or more of the following: electric, mechanical, or thermal energy generation, electric or thermal energy storage, geographically targeted electric demand side management and/or energy efficiency [1].

Utilities can use distributed resources to delay, reduce, or eliminate the need for additional generation, transmission, and distribution infrastructure. In other words, if a utility can use a distributed resource to serve new customer loads, then the utility avoids incurring costs associated with elements of its traditional "central generation and wires" solution-the one that it would normally use if the distributed resource was not an alternative. Utilities can also use distributed resources to market "value-added' services to specific areas within its service area or to specific customers. Such services might include electric service with very high reliability or better than normal power quality.

In addition to utility use, energy customers may install distributed resources to reduce overall energy costs ("bill management"), or to provide elements of electric service not available from the utility, such as high electric service reliability, high quality power, or heat. Also, due to deregulation and competitive trends in the electric utility industry, new market players such as electric service providers (ESPs) are entering territories once considered the exclusive domain of utilities. These ESPs are offering services to customers in direct competition with traditional utilities; distributed resources can be an important facet of ESPs' competitive offerings.

Given those premises and emerging trends in the electricity marketplace, there are strong indications utilities, their customers and their competitors (e.g., ESPs) may use distributed resources to reduce cost and/or to expand services. If so, there are potentially significant implications for hydrogen-fueled generation and storage technologies in the distributed resources market, and for the resulting total air emissions from electric power generation.

Objectives

The objective of this analysis is to determine the economic market potential for hydrogen-fueled generation and storage in the distributed utility market. This information can be of great value to commercial developers of hydrogen and hydrogen-fueled technologies, and also to research and development organizations.

A comparison with market potential for other distributed utility technologies (not fueled by hydrogen) is also valuable, particularly in regard to price and performance targets. To that end, hydrogen-fueled technologies are compared, as closely as possible, with technologies utilizing natural gas and Diesel fuel.

Another objective is to consider the potential air emissions implications in the U.S. due to market penetration of distributed generation fueled by hydrogen. That is done, in part, by estimating air emission impacts given economically viable market penetration of various distributed generation alternatives. A distributed generator's energy production cost affects the economic market potential for that type of device. That economic market potential for each type of distributed generator, in turn, affects the mix of generation - central and distributed - and thus total emissions from all generation.

A related objective of this study is to estimate the effects on economic market potential and air emissions from adding economic penalties associated with air emissions to the electric generation production cost, for central and distributed generation alike. The key effect of interest is the degree to which adding these environmental "externalities" to the cost for all types of generation increases or decreases the economic market potential for various distributed generation technologies. That, in turn, would also affect the total amount of air pollution from all generation, as described above.

Finally, hydrogen-based storage systems are evaluated to determine their application potential as distributed resources, and their resultant utility and customer benefits

Evaluation Scope

For this study Distributed Utility Associates (DUA) evaluated the merits of the use of distributed generation by electric utilities to meet the challenges of the new energy marketplace. The evaluation process involved a quantitative, cost-based analysis of the "economic market potential"[1] for use of distributed generation (compared to the conventional central/grid based alternative), by utilities, including the impacts of relevant customer factors such as cogeneration and local reliability.

---

1 *Economic* market potential is the portion of all increase in electric load ("load growth"), within the region or area being considered, that could be served most economically by a distributed generator (i.e., the portion of added load for which a distributed generator is the lowest cost option).

Distributed Generation Technologies Evaluated

There are literally hundreds of distributed generator systems that could be evaluated. Most of them will be distributed generators that convert liquid or gaseous fuel (usually Diesel fuel or natural gas) into electricity. The most common types of distributed generators are combustion turbines, internal combustion piston-driven engines, and fuel cells. All baseload distributed generators evaluated for this study are assumed to be capable of providing thermal energy via combined heat and power (irrespective of the economic merit of doing so).

For the record, the generation category of distributed resources also includes those that generate using renewable energy inputs, such as wind turbines and photovoltaics, though these alternatives are not within the scope of this study.

The distributed generation technologies evaluated in this study were either:

- judged by DUA to be commercially viable, reliable and serviceable, currently or within the next two years, or
- "emerging" small power generation options (e.g., fuel cells) with great promise as clean electricity sources, using renewable fuel (i.e., hydrogen).

Six peaking and six baseload distributed generation technologies were evaluated, for use with natural gas and hydrogen fuels. Their costs and heat rates are summarized in Table 1 (please see Appendix 1 for cost and performance details). Note that for baseload distributed generators the incremental cost associated with adding equipment needed for combined heat and power (CHP) is assumed to be $250 per kW. The extra cost is mostly for piping, heat exchangers, and engineering associated with gathering, moving, and storing waste heat from operation of the prime mover.

Environmental Externalities

Emission penalties for central generation are shown in Table 2. Emission penalties for the distributed generators burning fossil fuels are shown in Table 3. When distributed generators burn hydrogen, the SO, CO and VOC numbers go to zero. Central (utility) peaking resources are penalized about 3.956¢ per kWh delivered (i.e., accounting for transmission and distribution line losses) [3].

For peaking distributed generators the penalty ranges from about 2.3¢/kWh for the combustion turbine and Advanced Turbine System (ATS), to 8.25¢/kWh for Diesel engine generators with their high NOx output. Baseload distributed generators' emissions result in penalties that are much lower than those from peaking distributed generators or from central generation. This is due to their relatively high efficiency and low emissions, especially hydrogen fueled fuel cells.

Evaluation Methodology

This quantitative estimate of economic market potential is based solely on economic criteria that electric utility planners and engineers would use to evaluate costs and benefits associated with use of distributed generators. This is done because utilities are,

Base Load				
Type of Distributed Generator	**Heat Rate (Btu/kWh)**	**Non-Fuel Variable O&M (¢/kWh)**	**Total Installed Cost ($/kWh)**	**Annual Cost ($/kW-yr)****
Microturbine	11,500	1.0	600	69.0
Advanced Turbine System (ATS)	9,500	1.0	425	48.9
Conventional CT – Natural Gas	10,000	1.0	700	80.5
Diesel Engine - Hydrogen	8,800	3.0	500	57.5
Phos. Acid Fuel Cell – Natural Gas	8,500	1.5	1500	172.5
Phos. Acid Fuel Cell – Hydrogen	6,375	1.5	1500	172.5
PEM Fuel Cell – Natural Gas	8,500	1.5	1000	115.0
PEM Fuel Cell – Hydrogen	6,375	1.5	1000	115.0
Solid Oxide Fuel Cell – Natural Gas	7,600	1.5	1000	115.0
Solid Oxide Fuel Cell – Hydrogen	5,700	1.5	1000	115.0

Peak Load				
Type of Distributed Generator	**Heat Rate (Btu/kWh)**	**Non-Fuel Variable O&M (¢/kWh)**	**Total Installed Cost ($/kWh)**	**Annual Cost ($/kW-yr)****
Microturbine	13,000	1.5	500	57.5
Advanced Turbine System (ATS)	9,500	1.0	425	48.9
Combustion Turbine	11,000	1.5	550	63.3
Dual-Fuel Engine	9,500	3.0	500	57.5
Diesel Engine Genset	8,500	3.0	375	43.1
Spark-Gas Engine	9,700	2.5	375	43.1

**Using real fixed charge rate ("annualization" factor) of 0.115

Table 1. Distributed Generation Fuel Efficiency, Variable O&M, and Installed Cost

Assumption Parameters	**Unit Value** ($/ton)	**Unit Value** ($/lb)	**Amount** (lb/kWh)	Penalty (¢/kWh)
1. Oxides of Nitrogen (NO_x)	6500	3.25	.0032	1.07
2. Oxides of Sulfur (SO_x)	5200	2.60	.0059	1.58
3. Carbon Monoxide (CO)	870	0.44	.002	.09
4. Carbon Dioxide (CO_2)	22	0.01	1.00	1.13
5. Volatile Organic Compounds	5300	2.65	.00014	.04
6. Particulate	4000	2.00	.00019	.04
Total Penalty				3.95

Table 2. Central Generation Emissions Amounts and Penalties

Peak Load							
Distributed Generator Type	**NOx** (¢/kWh)	**SOx** (¢/kWh)	**CO** (¢/kWh)	**CO_2** (¢/kWh)	**VOCs** (¢/kWh)	**Particulate** (¢/kWh)	**Total** (¢/kWh)
Microturbine	1.04	.00	.15	1.37	.03	.00	2.6
Adv. Turbine System (ATS)	.76	.00	.15	1.37	.03	.00	2.3
Small Frame CT	1.04	.00	.11	1.0	.03	.00	2.2
Dual Fuel Engine	3.25	.03	1.35	1.0	.27	.40	6.3
Diesel Engine	4.88	.08	1.31	.95	.53	.52	8.25
Spark/Gas Engine	1.01	.03	.35	1.02	.40	.36	3.2

Base Load							
Distributed Generator Type	**NOx** (¢/kWh)	**SOx** (¢/kWh)	**CO** (¢/kWh)	**CO_2** (¢/kWh)	**VOCs** (¢/kWh)	**Particulate** (¢/kWh)	**Total** (¢/kWh)
Microturbine	.46	.00	.14	1.21	.03	.00	1.8
Adv. Turbine System (ATS)	.39	.00	.12	.95	.03	.00	1.5
Frame Combustion Turbine	.44	.00	.13	1.16	.03	.00	1.75
Fuel Cell	.00	.00	.00	.89	.00	.00	.89
Solid Oxide Fuel Cell	.00	.00	.00	.89	.00	.00	.89
PEM Fuel Cell	.00	.00	.00	.80	.00	.00	.80

Table 3. Distributed Generation Emission Penalties

in general, the most likely parties to have the clear financial incentive to use distributed generators (i.e., to reduce cost), the engineering resources required to evaluate and design distributed generation systems, and (perhaps most important) the sources of capital for distributed generation projects. Non-utility stakeholders that would install distributed resources would do so in response to prices that, to one extent or another and for the foreseeable future, will reflect utility cost.

The DUVal model developed by DUA and employed for this study uses a statistical methodology. Utility avoided costs resulting from the use of distributed generation rather than central generation vary widely among utilities and even within a given utility's service territory: some locations are inexpensive to serve and others can be quite expensive. These costs are modeled in DUVal as statistical distributions referred to as "value mountains," due to their characteristic shape. The cost to implement a distributed generation option is compared to the avoided cost value mountain. Locations that are more expensive to serve with central generation than with the distributed technology being analyzed represent the potential market for that technology (expressed in per cent).

Utility cost-of-ownership for distributed resources includes net cost incurred to own and operate the distributed generator. Key elements are purchase price, installation, financing, depreciation, taxes, fuel and maintenance costs, periodic overhauls, and insurance.

Utility benefits associated with use of the distributed generator are utility/grid-related costs that will not be incurred by the utility (i.e.; are an "avoided cost") if the distributed generator is used in lieu of the central/grid solution - This assumes that the distributed generator can provide the same or better service reliability and quality. In other words, for the utility, the benefit associated with use of a distributed generator is the avoided cost for otherwise needed fuel, O&M, and overhead expenses and generation, transmission, and distribution capacity (equipment) costs. Even if a project is deferred rather than avoided altogether, the time value of money often makes it worthwhile to use a temporary, redeployable, modular, and less financially risky distributed generation option rather than a more typical grid upgrade.

The maximum potential size of the market for distributed generation is assumed to be proportional to the load growth[2] in units of MW. Note again: No "embedded" load is considered - only annual increases in total load (load growth).

The estimate is performed for the year 2002. However, the estimate is assumed to be indicative of economic market potential for the years 2000 - 2004.

Quantitative economic market potential estimates are made for both peaking and baseload operation modes; for each mode, evaluations are made for distributed generation sited at substation and feeder locations (i.e., at or near loads).

<u>Operational Modes - Peaking and Baseload</u>

To serve as a peaking resource, a distributed generator must reduce utility infrastructure capacity needs. That, in turn, requires distributed generation to be operational during the utility's peak <u>demand</u> hours. Utility peak demand hours are the 100 - 200 hours during the year when demand for electricity is highest. The level of power draw on the utility system from all customers during those times dictates the required maximum capacity of the utility's generation system.

This concept is important for the analysis because the degree to which a distributed generator allows the utility to avoid procurement of additional capacity indicates the "capacity benefit" associated with distributed generation. Stated another way, to the extent that distributed generators operate so they offset the need for new/upgraded utility electric grid capacity, they receive a capacity credit commensurate with the amount of otherwise needed utility generation, transmission, and/or distribution equipment (capacity, infrastructure). Note that because peaking distributed generators operate for so few hours per year their total variable operating costs are not very significant in the evaluation, compared to their capital costs.

Baseload distributed generators operate for thousands of "full load equivalent" hours per year, in this case about 4700 hours. They receive the capacity credit described above if

---

Because embedded load was not included (i.e., distributed generation is not used to replace <u>existing</u> capacity needs such as replacing old equipment), economic market estimates may be significantly understated.

they generate during the utility's peak demand hours. But, for baseload distributed generators, it is usually more important to consider their cost-of-production for electric or thermal energy. Because they operate for many hours per year they must compete on an energy cost basis, rather than a capacity cost basis as is used for peaking units. The competition is usually lower-cost commodity electricity from the wholesale electric marketplace dominated by large generation facilities with economies of scale and generally low incremental cost of production. Therefore, installed capital cost and cost-of-production are both key criteria driving a baseload distributed generator's economic competitiveness. In turn, a baseload distributed generator's net cost-of-production is driven by fuel efficiency, fuel price, variable operations and maintenance costs for the particular distributed generator, and the degree to which waste heat can be sold for cogeneration.

Location Tvnes - Substation and Feeder

As depicted graphically in Figure 1 below, DUVal evaluates distributed generators at two location types: at a utility substation, and on a distribution feeder at or near a customer's site.

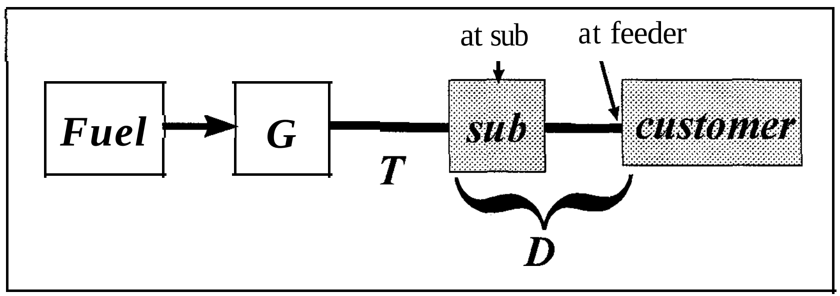

Figure 1. Evaluation Nodes

Several factors distinguish these two types of locations. Because most electric service outages occur between the substation and the load, a distributed generator sited at the substation does not receive as substantial a credit for reliability increases as does a distributed generator located on the feeder or at the customer's site. Distributed generators at substations do not defer the need for a feeder and thus do not receive an avoided cost credit for the cost of a feeder. Distributed generators at the substation are assumed to be larger and to qualify for purchase of gas at a wholesale/power plant procurement price; distributed generators on the feeder are assumed to use gas whose prices are higher because purchases are at a lower volume, "retail" level. An implicit assumption is that the required fuel type and distribution infrastructure are available at all sites considered.

Effects of Environmental Externalities

To capture the effects of air emissions on the relative competitiveness and attractiveness of distributed generation options, the evaluation includes economic market estimates without and with monetized values for environmental externalities associated with air emissions. In other words, distributed generation options are first evaluated for economic competitiveness without penalties imposed for air emissions. Then, economic market potential is estimated given an economic value (or in effect a penalty) assigned to each unit of pollution for six types of air emissions from distributed generators (see Assumptions section, below). Those penalties (expressed as $ per unit of pollution) are applied to emissions from both distributed generators and central generators. Distributed generators are then compared to the central/grid solution, given the traditional equipment, fuel and operation costs plus the monetized externalities, i.e., the economic value/penalty ascribed to air emissions.

Combined Heat and Power Oneration

Most distributed generators can provide useful and valuable thermal energy if "waste" heat from their operation is captured for processes or for space conditioning--a process called combined heat and power (CHP). For customers that use a lot of heat--especially industrial, institutional, and agricultural operations-CHP can improve the economics of specific distributed generation projects, and it can reduce a facility's overall cost of energy considerably. DUA estimates that 15% of new load could use CHP.

Hvdroaen Fueled Distributed Generators

The market potential evaluation described above was performed first for hydrogen fueled distributed generators, then again for fossil-fueled distributed generators for comparison purposes. For this study, hydrogen is assumed to be produced by large scale facilities with economies of scale and therefore reflects an optimistic price. Please see the Appendix for details of hydrogen price assumptions.

For the most part there are no significant technological changes required for distributed generators to use hydrogen rather than fossil fuel. Turbines are assumed to require some modest modifications, especially to combustors. Engines require modifications to subsystems or components such as fuel injection and seals. Fuel efficiency, NO_x emissions, and CO_2 emissions are assumed to be similar for natural gas and for hydrogen operation.

Fuel for Distributed Generators

In this report, the following assumptions apply to the fuels used in the various types of distributed generators:

- Hydrogen fuel is produced off-site (i.e., piped in from production facilities and not produced by reformer at the distributed generator site); cost assumed is $8/MMBtu
- Diesel engines - Diesel fuel (at a cost of $4.24/MMBtu).
- Dual Fuel Engines - Combination of natural gas and a small fraction of Diesel fuel.
- Microturbine, combustion turbine, Advanced Turbine System (ATS), spark gas engine, phosphoric acid fuel cell, proton exchange membrane (PEM) fuel cell, and solid oxide fuel cell - Natural gas or hydrogen.
- Natural gas at substation locations assumes supply from facilities with economies of scale; cost assumed is $3MM/Btu.

- Natural gas at feeder locations assumes higher infrastructure and delivery cost without economies of scale in production or supply; cost assumed is $5.6O/MMBtu.

Southwest United States

The evaluation of market potential for hydrogen-fueled technologies was performed separately for the special case of the Southwest United States, with its particular parameters of utility cost, hydrogen fuel supply and technology costs.

III. Economic Market Potential and Emissions Impacts of Distributed Generation

In this section, the economic market potential of hydrogen-fueled distributed generators is evaluated in the year 2002 for both peak load and base load operation modes. We also consider the effects of applying environmental penalties for air emissions, and compare to results for conventional fossil-fueled generators.

Utility Peaking Mode Distributed Generation Operation

Tables 4 - 7 contain the results of the evaluations for distributed generators operated as peaking resources. When considering these results, recall that peaking distributed generators operate during the utility's peak demand hours: the 100 - 200 hours during the year when demand for electricity is highest. This is done primarily to avoid the need for additional utility equipment or infrastructure (i.e., capacity) and related costs.

Tables 4 and 5 contain results for hydrogen-fueled peaking distributed generators without environmental penalties applied and with environmental penalties applied, respectively. Similarly, Tables 6 and 7 provide results for fossil-fueled peaking distributed generators, without and with environmental penalties considered, respectively.

In each table, the first column represents the estimated market potential in percent of the total possible market, (i.e., load growth), which is estimated to be 21,500 MW (21.5 GW) in 2002. Subsequent columns list emissions values in thousands of tons. Each table's first row shows emissions that would occur if central generation only is used to meet new electric load. Subsequent rows in the tables show the resulting total air emissions that would be emitted from allgeneration used to meet new load; i.e., total air emissions from the given distributed generator at the level of estimated economic market penetration plus emissions from central generation resources used to meet the portion of the new demand for which the given distributed generator is not economically viable.

The overall air emission impacts associated with use of peaking distributed generators, in terms of quantities of emissions products, is relatively small, due to the relatively few hours per year of operation associated with peaking units.

<u>Peaking Distributed Generators-Hvdroaen Fueled</u>

Tables 4 and 5 contain results for central generation, and for distributed generators fueled by hydrogen, used in peaking mode. Table 4 shows economic market share estimates and resulting air emissions assuming *nopenalties* areapplied for environmental externalities: the lowest market potential is 33% for the combustion turbine, while the spark gas engine is cost-competitive for over 90% of new load. Table 5 shows economic market share estimates and resulting air emissions assuming environmental penalties *are* applied; all technologies have higher estimated market potential than for the non-environmetal penalties case (compare Table 5 with Table 4), except for the Diesel engine, which loses about 14 percentage points of potential market share.

Peaking Distributed Generator Option	% of Market*	Thousands of tons					
		NO_x	SO_2	CO	CO_2	VOCs	Particulates
System Only	100.0	7.1	13.1	4.4	2219	0.3	6.9
Microturbine	37.9	7.0	8.1	5.9	2204	0.2	4.3
Adv. Turbine System (ATS)	83.5	5.3	2.2	5.8	1811	0.1	1.1
Conventional Comb. Turbine	32.6	7.0	8.8	5.7	2267	0.2	4.6
Dual Fuel Engine	44.4	13.5	7.3	5.1	1314	0.2	3.8
Diesel Genset	68.5	24.4	4.1	45.6	1822	0.1	2.2
Spark Gas Engine	90.7	6.7	1.2	16.0	1809	0.0	0.6

*Total potential market in 2002 = 21.5 GW/yr

Table 4. Peak Load Central and Hydrogen-Fueled Distributed Generation: Market Potential and Air Emissions, No Environmental Penalties

Peaking Distributed Generator Option	% of Market*	Thousands of tons					
		NO_x	SO_2	CO	CO_2	VOCs	Particulates
System Only	100.0	7.1	13.1	4.4	2219	0.3	6.9
Microturbine	50.3	7.0	6.5	6.4	2510	0.2	3.4
Adv. Turbine System (ATS)	96.2	5.0	0.5	6.0	2051	0.0	0.3
Conventional Comb. Turbine	43.9	7.0	7.3	6.2	2284	0.2	3.9
Dual Fuel Engine	47.6	14.0	6.9	5.2	2136	0.2	3.6
Diesel Genset	54.6	20.9	5.9	37.3	2006	0.1	3.1
Spark Gas Engine	98.3	6.7	0.2	17.0	2090	0.0	0.1

*Total potential market in 2002 = 21.5 GW/yr

Table 5. Peak Load Central and Hydrogen-Fueled Distributed Generation: Market Potential and Air Emissions, With Environmental Penalties

<u>Peaking Distributed Generators-Natural Gas Fueled</u>

Tables 6 and 7 contain results for central generation, and for distributed generators fueled by natural gas, used in peaking mode. Table 6 shows economic market share estimates and resulting air emissions assuming *no penalties* areapplied for environmental externalities, and Table 7 shows economic market share estimates and resulting air emissions assuming environmental penalties *are* applied.

Comparing the results in Table 6 with the results in Table 4 shows that, without considering externalities from air emissions, using hydrogen fuel in place of natural gas negatively impacts the market potential of all peaking distributed generator technologies, albeit to varying degrees. Diesel engines' market potential drops the most, by about 30 points, to 68.5%. Spark gas engines drop about 7%, but are still cost-effective for almost 91% of the market. Conventional combustion turbines have the smallest potential, at about 33% of the market.

Peaking Distributed Generator Option	% of Market*	Thousands of tons					
		NO_x	SO_x	CO	CO_2	VOCs	Particulates
System Only	100.0	7.1	13.1	4.4	2219	0.3	6.9
Microturbine	56.0	6.7	5.8	6.2	2543	0.3	3.0
Adv. Turbine System (ATS)	94.0	5.1	0.8	5.5	2055	0.3	0.4
Conventional Comb. Turbine	44.9	6.6	7.2	5.3	2286	0.3	3.8
Dual Fuel Engine	58.8	15.6	5.5	39.8	2117	1.4	5.4
Diesel Genset	98.4	31.9	0.8	63.6	1942	4.2	5.6
Spark Gas Engine	97.5	6.7	0.5	16.9	2091	3.2	3.9

*Total potential market in 2002 = 21.5 GW/yr

Table 6. Peak Load Central and Natural Gas-Fueled Distributed Generation: Market Potential and Air Emissions, No Environmental Penalties

Peaking Distributed Generator Option	% of Market*	Thousands of tons					
		NO_x	SO_x	CO	CO_2	VOCs	Particulates
System Only	100.0	7.1	13.1	4.4	2219	0.3	6.9
Microturbine	72.4	6.6	3.6	6.7	2638	0.2	1.9
Adv. Turbine System (ATS)	99.1	5.0	0.1	5.6	2046	0.3	0.1
Conventional Comb. Turbine	62.0	6.4	5.0	5.7	2311	0.3	2.6
Dual Fuel Engine	51.7	14.6	6.4	35.5	2129	1.3	5.5
Diesel Genset	89.1	29.5	2.0	58.0	1968	3.9	5.7
Spark Gas Engine	99.1	6.7	0.3	17.1	2089	3.2	3.9

* Total potential market in 2002 = 21.5 GW/yr

Table 7. Peak Load Central and Natural Gas-Fueled Distributed Generation: Market Potential and Air Emissions, With Environmental Penalties

Second, all hydrogen-fueled technologies have lower estimated market potential than their natural gas-fired counterparts, to varying degrees (compare Table 7 to Table 5). Microturbines and conventional combustion turbines lose about 22 and 18 percentage points, respectively, and the Diesel engine loses about 14.5 points, of potential market share. Dual fuel engines, ATSs, and spark gas engines drop only slightly.

Utility Baseload Mode Distributed Generation Operation

The estimated economic market potential for base load distributed generators is given in Tables 8 through 11. Again there are a pair of tables for hydrogen-dueled generators, without and with environmental externalities applied, and a similar pair of tables for natural gas-fueled generators. Values in the first data column are the estimates of potential market share for each distributed generator type, in percent of the total (21.5 GW in 2002). Subsequent columns provide data on resulting total air emissions for the central/distributed generation mix, in thousands of tons.

As a brief review: Baseload distributed generators operate during the utility's load hours-in this evaluation the 4,774 "full load equivalent" hours during the year when virtually all demand for energy occurs. They are deployed for one or both of two primary benefits:

1) To allow the utility to avoid costs related to adding utility generation, transmission, or distribution equipment/infrastructure (i.e., capacity), and

2) To provide cost-competitive energy-primarily electric energy but possibly including mechanical and thermal energy-resulting in reduced overall cost-of-service, and possibly reduced net fuel use and net air emissions.

For the evaluation, 15% of load was assumed to be coincident with thermal loads such that a distributed generator with combined heat and power (CHP) could serve electric and thermal loads. All baseload distributed generators were allowed to serve that market. CHP can only occur at feeder locations-where demand and thermal loads are.
These results indicate how baseload distributed generators' costs compare with the spread of total cost-of-service throughout the utility service area-the cost to meet new load by making necessary additions to the utility infrastructure.

Baseload Distributed Generators - Hydrogen Fueled

Hydrogen-fueled distributed generators, without considering environmental externalities, are not cost-effective across the board when used in baseload application (Table 8).

Table 9 shows that applying environmental externalities to hydrogen-fueled baseload distributed generators raises market shares from zero to very significant amounts; the lone exception being the Diesel engine, which is still not cost-effective at all. Both the PEM and Solid Oxide tie1 cells are cost-effective for all the new load.

Baseload Distributed Generator Option	% of Market*	Thousands of tons					
		NO_x	SO_x	CO	CO_2	VOCs	Particulates
System Only	100.0	169.5	312.5	105.9	52,969	7.4	164.2
Microturbine	0.0	169.5	312.5	105.9	52,969	7.4	164.2
Adv. Turbine System (ATS)	0.0	169.5	312.5	105.9	52,969	7.4	164.2
Diesel Genset	0.0	169.5	312.5	105.9	52,969	7.4	164.2
Phosphoric Acid Fuel Cell	0.0	169.5	312.5	105.9	52,969	7.4	164.2
PEM Fuel Cell	0.0	169.5	312.5	105.9	52,969	7.4	164.2
Solid Oxide Fuel Cell	0.0	169.5	312.5	105.9	52,969	7.4	164.2

***Total potential market in 2002 = 21.5 GW/yr**

Table 8. Base Load Central and Hydrogen-Fueled Distributed Generation: Market Potential and Air Emissions, No Environmental Penalties

Baseload Distributed Generator Option	% of Market*	Thousands of tons					
		NO_x	SO_x	CO	CO_2	VOCs	Particulates
System Only	100.0	169.5	312.5	105.9	52,969	7.4	164.2
Microturbine	13.9	156.1	269.1	119.1	53,819	6.4	141.4
Adv. Turbine System (ATS)	15.5	152.8	264.1	111.8	52,325	6.3	138.8
Diesel Genset	0.0	169.5	312.5	105.9	52,969	7.4	164.2
Phosphoric Acid Fuel Cell	34.8	110.5	203.8	69.1	45,934	4.8	107.1
PEM Fuel Cell	100.0	0.0	0.0	0.0	32,775	0.0	0.0
Solid Oxide Fuel Cell	100.0	5.1	1.0	0.0	29,287	0.0	0.0

*Total potential market in 2002 = 21.5 GW/yr

Table 9. Base Load Central and Hydrogen-Fueled Distributed Generation Market Potential and Air Emissions, With Environmental Penalties

Baseload Distributed Generators - Natural Gas Fueled

Tables 10 and 11 contain results for fossil-fired generation operated as baseload resources in 2002, without and with economic penalties for air emissions, respectively. The Advanced Turbine System (ATS) is the most attractive natural gas fired baseload distributed generator option (see Table 10): it is less expensive than the utility grid option for about 62% of load growth. Microturbines are cost-effective for about 13% of new load, and combustion turbines could address about 4% of new load cost-effectively (almost all instances involving cogen). Proton Exchange Membrane (PEM) and Solid Oxide fuel cells operating on $WMMBtu hydrogen fuel would compete economically for only about 0.1% of the market. Phosphoric Acid fuel cells operating on natural gas are not cost effective for any of the market.

Baseload Distributed Generator Option	% of Market*	Thousands of tons					
		NO_x	SO_x	CO	CO_2	VOCs	Particulates
System Only	100.0	169.5	312.5	105.9	52,969	7.4	164.2
Microturbine	13.1	156.9	271.6	112.9	53,770	7.1	142.7
Adv. Turbine System (ATS)	61.7	103.0	119.7	123.0	50,403	6.0	62.9
Conventional Comb. Turbine	3.8	165.6	300.6	107.2	52,909	7.4	158.0
Phosphoric Acid Fuel Cell	0.0	169.5	312.5	105.9	52,969	7.4	164.2
PEM Fuel Cell	0.1	169.3	312.2	105.8	52,960	7.4	164.0
Solid Oxide Fuel Cell	0.1	169.3	312.2	105.8	52,955	7.4	164.0

*Total potential market in 2002 = 21.5 GW/yr

Table 10. Base Load Central and Natural Gas-Fueled Distributed Generation: Market Potential and Air Emissions, No Environmental Penalties

Baseload Distributed Generator Option	% of Market*	Thousands of tons					
		NO_x	SO_x	CO	CO_2	VOCs	Particulates
System Only	100.0	169.5	312.5	105.9	52,969	7.4	164.2
Microturbine	100.0	73.0	0.0	159.3	59,087	5.1	0.0
Adv. Turbine System (ATS)	100.0	61.7	0.0	133.6	48,811	5.1	0.0
Conventional Comb. Turbine	100.0	66.8	0.0	138.7	51,380	7.1	0.0
Phosphoric Acid Fuel Cell	100.0	0.0	0.0	0.0	43,673	0.0	0.0
PEM Fuel Cell	100.0	0.0	0.0	0.0	43,673	0.0	0.0
Solid Oxide Fuel Cell	100.0	5.1	1.0	0.0	39,049	0.0	0.0

*Total potential market in 2002 = 21.5 GW/yr

Table 11. Base Load Central and Natural Gas-Fueled Distributed Generation: Market Potential and Air Emissions, With Environmental Penalties

When environmental externalities are applied, <u>all</u> natural gas-fueled distributed generators are cost-effective for <u>all</u> new load when operated in base load mode (see Table 11). This is a dramatic reversal of the aforementioned case with no environmental penalties, when only the ATS had a significant market potential (Table 10).

<u>Utilitv Baseload Distributed Generators - Observations</u>

If environmental externalities associated with air emissions are monetized and then applied as a penalty for several thousand hours of operation per year, then the distributed generators evaluated would have a significant economic advantage. Even fuel cells fueled with very expensive hydrogen fuel - at about $8/million BTU - are economically competitive. A key driver of this result is the fact that state-of-the-art and emerging small generator technologies can and often do emit fewer air pollutants per kWh produced than do “average” or even many new central power plants. It is also driven to a small extent by the transmission and distribution line losses associated with central power plants, which must produce more kWh than distributed generators per kWh delivered to compensate for those losses.

Note that baseload distributed generators tend to be deployed at substation locations. That is due to the fact that natural gas price is assumed to be significantly higher for feeder locations than for substation locations, for a variety of reasons. Note also that the fuel price advantage at substation locations can be offset, to some degree, by the fact that distributed generators located at substation locations are farther from loads than feeder distributed generators (i.e., they are upstream from most outages) and thus they provide much less of a benefit due to reliability improvement. The one important exception to the fuel cost advantage is when distributed generators are used in combined heat and power (CHP) applications.

The following caveats are important to keep in mind when considering the results for baseload generators:

- Peaking and baseload distributed generators were both evaluated as solutions for the same "market" - all of the forecast electric load growth. In reality, of course, these are very different applications or market segments with very different needs and decision drivers. Peaking units primarily offset expenditures for fixed capital equipment; baseload distributed generators are used because they result in both reduced need for capital equipment (upstream to bolster the electric grid) and lower overall energy production cost, usually due to lower variable maintenance costs and/or lower fuel cost per kWh produced than for grid-based electricity. Also note that, at some point, these two market segments will begin to overlap.

- Market shares are estimated without regard to substitutes. In actuality distributed generators would have to compete against other distributed generators as well as the grid.

- Dual fuelled engines are the lowest cost baseload distributed generation option, and therefore are cost-effective for many circumstances. However, significant deployment of these engines may be problematic because of air emissions, especially NO_x.

- Natural gas fuel is assumed for all baseload generation options except PEM and Solid Oxide fuel cells, whose fuel is hydrogen. In addition, the Solid Oxide fuel cell is assumed to have a Diesel engine component.

- For gas fired options, market share values may be reduced based on the availability of natural gas fuel.

- Results reflect a 15% chance that the feeder location can use heat from combined heat and power, and that the heat is worth the price that would have been paid to generate the heat with natural gas.

Hydrogen Fueled Distributed Generation in the Southwestern United States

<u>Enerav Marketplace Overview</u>

In general terms, the energy marketplace in the Southwestern United States is characterized by somewhat lower costs for new transmission and distribution capacity than the U.S. as a whole, probably due to population distribution patterns and densities.

The Southwest has somewhat higher electric energy generation cost (i.e., *incremental* cost for each kilowatt-hour) than the U.S. This is due primarily to the relatively small proportion of coal in the region's generation fuel mix, and also possibly due to higher wages paid to workers performing variable operations and maintenance tasks.

T&D line losses are somewhat higher for the region because ambient annual average temperatures are higher and because of significant air conditioning loads on-peak.

Fuel prices are assumed to be the same as the national average.

Southwest Results Overview

Utility perspective results for the Southwest were quite similar to those for the U.S. as a whole. Without monetized environmental externalities, *peaking* distributed generators are economically competitive for some or most new load. Adding penalties for emissions affects results considerably, adding significantly to economic competitiveness of hydrogen fueled distributed generators. Detailed results are presented below in Tables 12 through 15.

Peaking Distributed Generator Option	% of Market*	Thousands of tons					
		NO_x	SO_x	CO	CO_2	VOCs	Particulates
System Only	100.0	0.6	1.2	0.4	197	0.0	0.6
Microturbine	26.1	0.6	0.9	0.3	195	0.0	0.5
Adv. Turbine System (ATS)	74.2	0.5	0.3	0.1	163	0.0	0.2
Conventional Comb. Turbine	21.7	0.6	0.9	0.3	199	0.0	0.5
Dual Fuel Engine	32.7	1.0	0.8	0.3	138	0.0	0.4
Diesel Genset	58.2	1.9	0.5	0.2	166	0.0	0.3
Spark Gas Engine	81.6	0.6	0.2	0.1	162	0.0	0.1

*Total potential market in 2002 = 1.9 GW/yr

Table 12. Peak Load Central and Hydrogen-Fueled Distributed Generation in the Southwestern US: Market Potential and Air Emissions, No Environmental Penalties

Peaking Distributed Generator Option	% of Market*	Thousands of tons					
		NO_x	SO_x	CO	CO_2	VOCs	Particulates
System Only	100.0	0.6	1.2	0.4	197	0.0	0.6
Microturbine	41.9	0.6	0.7	0.2	194	0.0	0.4
Adv. Turbine System (ATS)	94.2	0.4	0.1	0.0	154	0.0	0.0
Conventional Comb. Turbine	34.2	0.6	0.8	0.1	201	0.0	0.4
Dual Fuel Engine	43.0	1.2	0.7	0.2	119	0.0	0.3
Diesel Genset	45.4	1.6	0.6	0.2	173	0.0	0.3
Spark Gas Engine	95.9	0.6	0.0	0.0	156	0.0	0.0

*Total potential market in 2002 = 1.9 GW/yr

Table 13. Peak Load Central and Hydrogen-Fueled Distributed Generation in the Southwestern US: Market Potential and Air Emissions, With Environmental Penalties

Peaking

Upon applying penalties for emissions, economic market potential for conventional combustion turbines rises from 22% to 34%, microturbines' economic market potential increases from 26% to 42%, the portion of the market for which ATSs are economically viable increases from 74% to 94%, while that for spark engines improves from 81% to 96%. The economic market share increase for dual-fueled engines was more modest, changing from 33% to 43%. As with U.S. results, Diesel engines' economic viability drops—in this case from 58% to 45%—if penalties are introduced, due mostly to the high NOx emissions.

Baseload Distributed Generator Option	% of Market*	Thousands of tons					
		NO_x	SO_x	CO	CO_2	VOCs	Particulates
System Only	100.0	15.1	27.8	9.4	4714	0.7	14.6
Microturbine	0.0	15.1	27.8	9.4	4714	0.7	14.6
Adv. Turbine System (ATS)	0.1	15.1	27.8	9.4	4713	0.7	14.6
Diesel Genset	0.0	15.1	27.8	9.4	4714	0.7	14.6
Phosphoric Acid Fuel Cell	0.0	15.1	27.8	9.4	4714	0.7	14.6
PEM Fuel Cell	0.1	15.1	27.8	9.4	4713	0.7	14.6
Solid Oxide Fuel Cell	0.1	15.1	27.8	9.4	4712	0.7	14.6

***Total potential market in 2002 = 1.9 GW/yr**

Table 14. Base Load Central and Hydrogen-Fueled Distributed Generation in the Southwestern US: Market Potential and Air Emissions, No Environmental Penalties

Baseload Distributed Generator Option	% of Market*	Thousands of tons					
		NO_x	SO_x	CO	CO_2	VOCs	Particulates
System Only	100.0	15.1	27.8	9.4	4714	0.7	14.6
Microturbine	14.5	13.8	23.8	7.6	4745	0.6	12.5
Adv. Turbine System (ATS)	34.2	11.8	18.3	3.1	4333	0.4	9.6
Diesel Genset	0.7	15.3	27.6	9.4	4684	0.7	14.5
Phosphoric Acid Fuel Cell	100.0	0.0	0.0	0.0	273	0.0	0.0
PEM Fuel Cell	100.0	0.0	0.0	0.0	3641	0.0	0.0
Solid Oxide Fuel Cell	100.0	0.4	0.1	0.0	3256	0.0	0.0

***Total potential market in 2002 = 1.9 GW/yr**

Table 15. Base Load Central and Hydrogen-Fueled Distributed Generation in the Southwestern US: Market Potential and Air Emissions, With Environmental Penalties

<u>Baseload</u>

If penalties for emissions are applied, economic viability for conventional ATSs using hydrogen fuel rises from near zero to about 34% of the market. For microturbines, economic market potential increases from none to 14.5%. All fuel cells fare quite well, with economic market share increasing from near zero to 100%. Hydrogen fueled Diesel gensets are economically viable for a small 0.7% of the market if penalties are applied.

Fuel Cell Market Potential

Figures 2 through 5 below indicate the fuel efficiency and installed cost required for fuel cells to be cost-effective, given three fuel prices, under four situations. In each figure, plots of fuel efficiency vs. installed cost are given for three fuel price levels, levels that represent the range of plausible fuel prices. The four situations are:

- fuel cells are cost effective for 50% of electric utility load growth without applying environmental externalities,
- fuel cells are cost effective for 50% of electric utility load growth with environmental externalities applied,
- fuel cells are cost effective for 10% of electric utility load growth without applying environmental externalities,
- fuel cells are cost effective for 10% of electric utility load growth with environmental externalities applied,

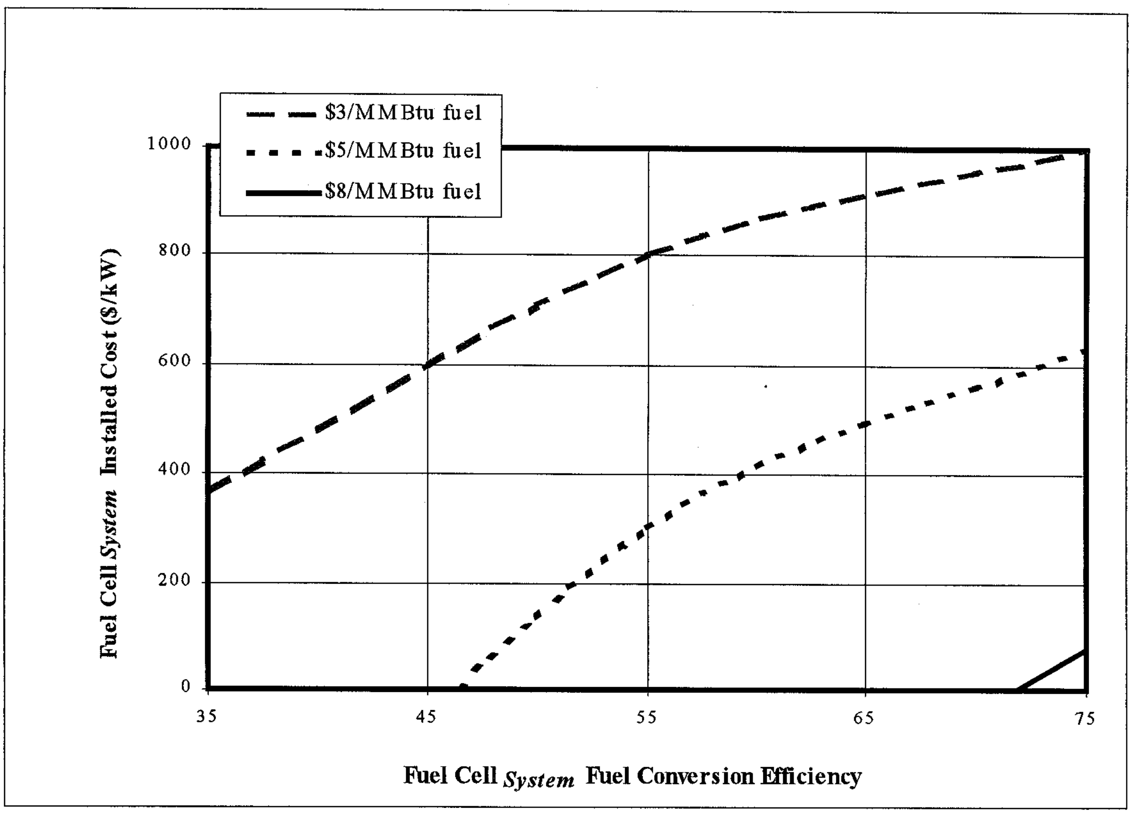

Figure 2. Fuel Cell System Installed Cost vs. Conversion Efficiency: 50% Market Share, No Environmental Externalities

Using Figure2 as an example, given a fuel cell with 55% fuel conversion efficiency, if fuel price is $5 per million Btu ($/MMBtu) then the fuel cell installed cost can be

$300/kW or less for fuel cells to be competitive for 50% of load growth. If fuel price is $3/MMBtu then the 55% fuel efficient fuel cells' installed cost can be about $800/kW or less to be cost-competitive for 50% of electric load growth in the U.S.

As shown in Figure 3, if monetary externalities are added for air emissions (from central plants and from fuel cells), the allowable installed cost for distributed fuel cells can be much higher—for a given fuel efficiency—if fuel cells are to be cost-effective for 50% of U.S. load growth. Specifically, if fuel efficiency is 55%, then installed cost must be $2,100/kW or less if fuel price is $5/MMBtu, and can be as high as $2,600/kW if fuel price is as low as $3/MMBtu.

Figure 4 and Figure 5 show the allowable installed costs for fuel cells to be cost-effective for 10% of the growth in demand for electricity. Again using fuel cells with a conversion efficiency of 55%, allowable costs are about $520/kW for $5/MMBtu fuel, and about $1030/kW for $3/MMBtu fuel (Figure 4). And, if environmental externalities are applied, allowable costs can be about $2350/kW for $5/MMBtu fuel, and about $2830/kW for $3/MMBtu fuel (Figure 5).

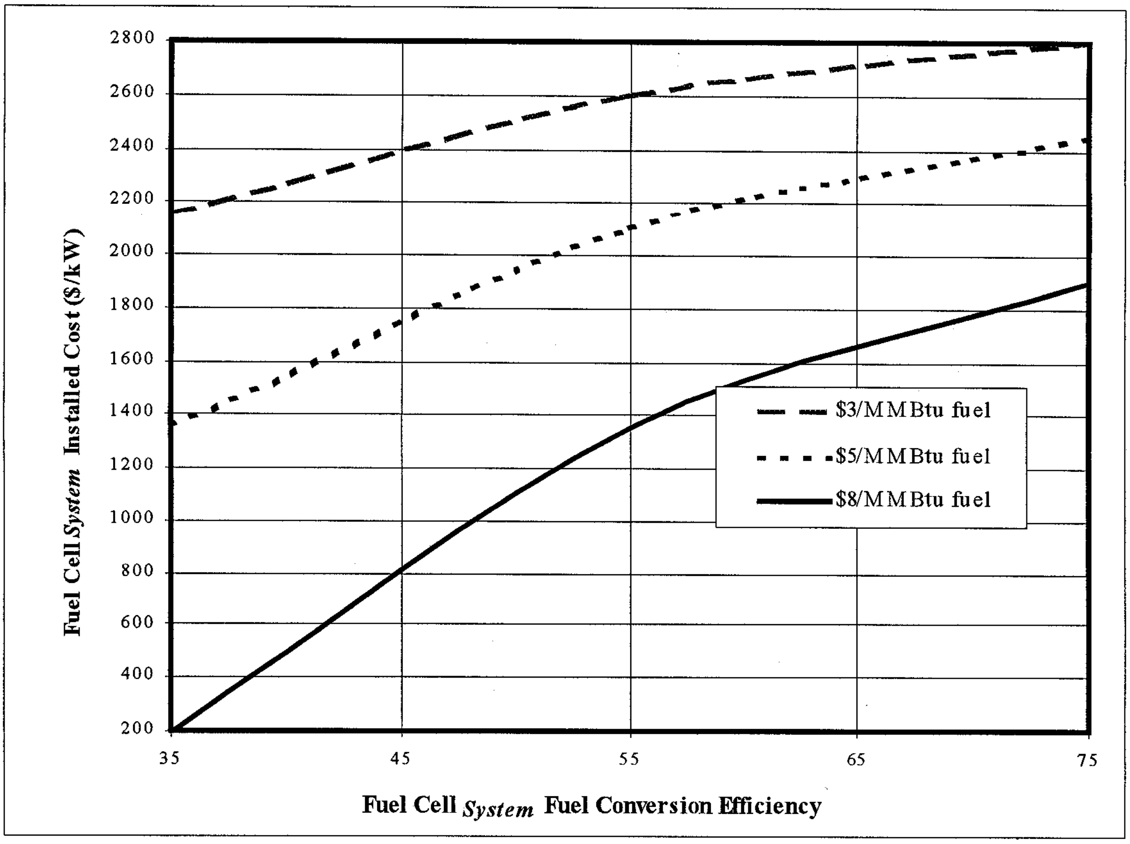

Figure 3. Fuel Cell System Installed Cost vs. Conversion Efficiency: 50% Market Share, With Environmental Externalities

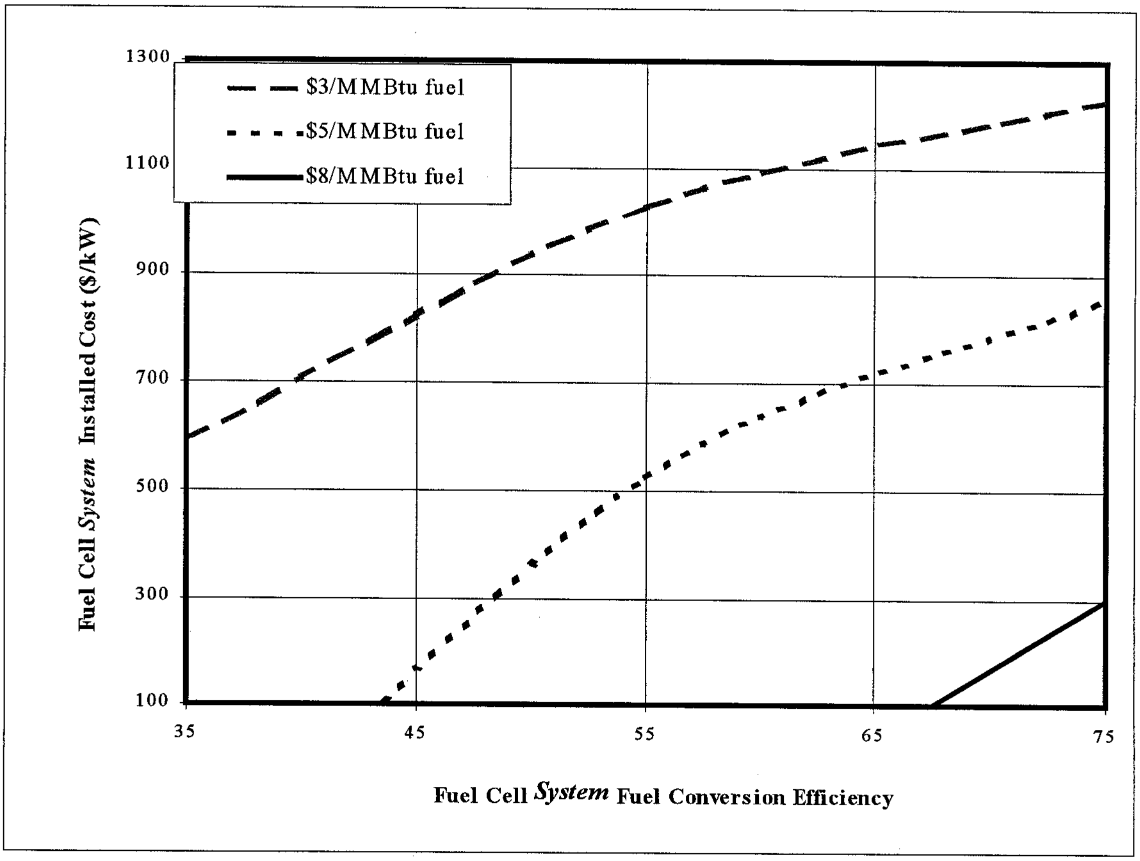

Figure 4. Fuel Cell System Installed Cost vs. Conversion Efficiency: 10% Market Share, No Environmental Externalities

Note that, in general, as fuel cells compete for larger and larger portions of the electric load growth they are more and more likely to have to compete in locations where the marginal cost for utility electric service may be low or quite low. That is why the allowable installed cost is much lower for the 55% efficient fuel cell noted above if the fuel cell is to be cost-effective for 50% of load growth.

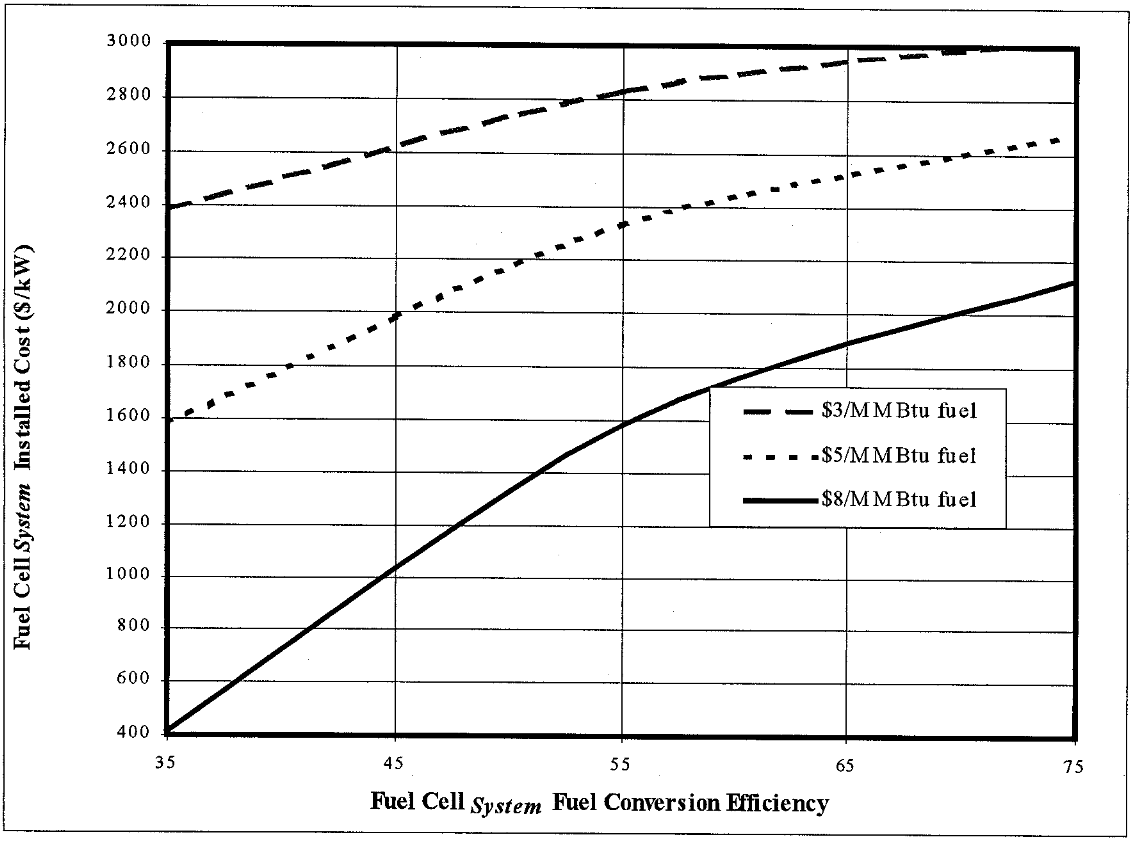

Figure 5. Fuel Cell System Installed Cost vs. Conversion Efficiency: 10% Market Share, With Environmental Externalities

IV. Conclusions

It seems clear from the results of this study that distributed generation has significant economic potential, and could be a valuable part of an overall strategy to reduce greenhouse gases and other air emissions. It is also apparent that hydrogen fueled technologies can have significant market potential, even though they are not quite as cost-effective as fossil fueled alternatives. The challenge is to maximize the potential positive air emission impacts while capturing the economic benefits of distributed generation.

Peaking Distributed Generators

Economic market estimates for peaking distributed generators used by utilities show that small distributed generation has significant potential to reduce utility capital equipment cost and thus overall service cost, whether or not penalties for air emissions are applied. This is true even for the distributed generator option with the most significant emissions-Diesel engines-whose environmental penalty was more than 8¢ per kWh. Other distributed generator options are even more cost-effective.

Tables 4 through 7 in Section III show that hydrogen fueled technologies can also be cost-effective for a significant percentage of new load in peaking applications, particularly when penalties for air emissions are factored into the equation. The market potential for these technologies will depend to some extent on the costs of supplying the hydrogen fuel. For some technologies, such as the Advanced Turbine System, dual fuel engine, and spark gas engine, the difference in cost between using natural gas versus hydrogen for these technologies does not result in a large difference in overall cost-effectiveness. For others, such as the Diesel engine, microturbine, and combustion turbine, the difference is much more significant.

In many cases, Diesel engines and other distributed generation alternatives have a low initial cost relative to many grid-based solutions involving central generation and “wires” (transmission and distribution) systems; initial cost can be the most significant factor in the evaluation of cost-effectiveness. Qualitatively, engines offer an increasingly important way for utilities to reduce risk associated with more permanent grid-based solutions in times of growing uncertainty in the utility marketplace. Furthermore, because peaking distributed generators only operate for a few hundred hours per year, they do not emit a significant amount of air pollutants, in total.

Given that result, it seems that the use of distributed generators for utility peak load applications is likely to have a somewhat important economic impact without a significant air emission impact overall, negative or positive.

Similarly, utility customers may be in a position to use peaking distributed generators to avoid increasingly common peak demand charges. Increasingly, as utilities are forced to unbundle their total cost for electricity into fixed and variable components-e.g. for generation, transmission, and distribution equipment, and for fuel-fixed costs associated generation, transmission and distribution equipment are showing up as components of utility charges, called demand charges. However, note that utility peak demand charges typically apply for 650 - 1300 hours per year. That means that a customer must operate the peaking distributed generator for that many hours per year to receive a full demand charge reduction.

Another driver of customer use of peaking distributed generators is improvement of service reliability. If utility customers provide high-value-added products and/or services, then they may want to install distributed generators to improve the reliability of the electric service beyond levels of reliability that a utility can or will offer. That may be the most compelling reason of all for specific customers to install peaking distributed generators. If reliability-related benefits are coupled with a credit for peak electric demand reduction (from the utility), then distributed generators may be real economic winners for customers.

Baseload Distributed Generators

Economic market estimates for baseload distributed generators have significant potential to reduce overall electricity cost and air emissions. However, in most circumstances central grid electricity seems likely to be competitive with electricity from most types of distributed generators, possibly for the next decade. This is primarily due to two factors: 1) a maturing central generation fleet with relatively low financial carrying costs, and 2) low incremental production cost for electric energy from nuclear, hydro, coal fueled, and more modern and efficient combustion turbine-based power plants.

Recall that for distributed generators to be cost-effective baseload resources for utilities, the distributed generators' total benefit usually must include both reduced need for expensive generation, transmission and distribution upgrades, and lower overall energy production cost over many hours per year. However, as noted before, usually the electric grid provides lower cost electric energy than most baseload distributed generators can generate.

This is indicated by the results in Tables 8 and 10 in Section III. Except for the Advanced Turbine System (ATS), with its combination of low cost and high efficiency, no other baseload distributed generator option that was considered could compete, except for a conventional combustion turbine with a marginal market share. Hydrogen fueled generators were not competitive at all, owing mostly to high fuel costs coming into play with the higher number of hours of operation per year.

But, because some distributed generators have lower emissions per kWh than the central generation mix, they begin to develop a substantial economic advantage when environmental externalities are applied to baseload operation. In fact, the economic market potential of natural gas fired distributed generation is virtually 100% for baseload applications in 2002 (Table 9), and for some hydrogen fueled technologies (i.e., fuel cells) it is very good (Table 11).

Air Emissions

Beyond the economic advantage offered by distributed generators, the potential to reduce air emissions is dramatic. Most notably, if externalities were applied:

- ✓ CO_2 emissions from generation needed to meet new demand for electricity could be reduced by as much as 40% in peaking applications, and 45% in applications.

- ✓ NO_x emissions from new generation could be reduced by about 30% if advanced combustion turbines were deployed instead of the conventional central generation assumed, and NO_x emissions could even be eliminated from new sources if the entire fleet of new generation was composed of fuel cells with competitive economics, including those fueled by hydrogen.

- ✓ Particulate emissions would also be virtually eliminated if distributed generators were deployed in lieu of central generation having a large coal component.

In addition, it is estimated that about 15% of new load would have sufficient thermal load to support combined heat and power applications. Therefore, air emissions could be further reduced because the waste heat recuperated from the CHP plant translates into fuel that does not have to be burned to supply the heat.

Appendix: Study Assumption Details

Distributed Generation Cost and Performance Assumptions

The distributed generators evaluated for this study, along with their installation costs and fuel requirements (heat rates), are shown in Table A-1 below.

Base Load				
Type of Distributed Generator	**Heat Rate (Btu/kWh)**	**Non-Fuel Variable O&M (¢/kWh)**	**Total Installed Cost ($/kWh)**	**Annual Cost ($/kW-yr)****
Microturbine	11,500	1.0	600	69.0
Advanced Turbine System (ATS)	9,500	1.0	425	48.9
Conventional CT – Natural Gas	10,000	1.0	700	80.5
Diesel Engine - Hydrogen	8,800	3.0	500	57.5
Phos. Acid Fuel Cell – Natural Gas	8,500	1.5	1500	172.5
Phos. Acid Fuel Cell – Hydrogen	6,375	1.5	1500	172.5
PEM Fuel Cell – Natural Gas	8,500	1.5	1000	115.0
PEM Fuel Cell – Hydrogen	6,375	1.5	1000	115.0
Solid Oxide Fuel Cell – Natural Gas	7,600	1.5	1000	115.0
Solid Oxide Fuel Cell – Hydrogen	5,700	1.5	1000	115.0

Peak Load				
Type of Distributed Generator	**Heat Rate (Btu/kWh)**	**Non-Fuel Variable O&M (¢/kWh)**	**Total Installed Cost ($/kWh)**	**Annual Cost ($/kW-yr)****
Microturbine	13,000	1.5	500	57.5
Advanced Turbine System (ATS)	9,500	1.0	425	48.9
Combustion Turbine	11,000	1.5	550	63.3
Dual-Fuel Engine	9,500	3.0	500	57.5
Diesel Engine Genset	8,500	3.0	375	43.1
Spark-Gas Engine	9,700	2.5	375	43.1

**Using real fixed charge rate ("annualization" factor) of 0.115

Table A-1: Distributed Resource (DR) Fuel Efficiency, Variable O&M, and Installed Cost

Hydrogen Fuel for Distributed Generators

Fuel cells use hydrogen directly. As a result, fuel cells operating on natural gas normally require "reformers" that extract hydrogen from natural gas's hydrocarbons. Reformers are assumed to cost about $350/kW and they are assumed to convert natural gas to hydrogen at with a conversion efficiency of about 75%.

For this study, we assume that hydrogen-fueled fuel cell systems are fueled by delivered hydrogen supplied by a remote source. This eliminates the need for a hydrogen-producing component at the fuel cell, either a reformer or an electrolyzer. As a result, the fuel cell system's cost includes only the fuel cell stack and power conditioning.

The cost of delivered hydrogen can vary widely. Recent studies by Joan Ogden, et. al. [3] show a range of delivered hydrogen costs as listed in Table A-2. For our analysis, we assumed a cost of $8.5/GJ or $8/MMBtu.

Hydrogen Source	**Delivered Cost ($/GJ)**	**Delivered Cost ($/MMBTU)**	**Comments**
Grid electrolysis	~15	~14	Off-peak electricity Includes storage
Renewable electrolysis (PV)	~23	~22	Large scale Includes storage
On-site reformer	14-40	13-38	Assumes natural gas Depends on size Includes storage
Track delivery of H_2 from central reformer	~15	~14	Assumes natural gas
Pipeline delivery from central reformer	8-13	7.5-12	Assumes natural gas Depends on pipe length
By-product hydrogen	12-30	11-28	Depends on source About 60 MW total available in LA basin

Table A-2: Delivered Costs for Hydrogen Fuel

Since fuel cells use hydrogen directly, fuel cells operating on natural gas need reformers that extract hydrogen from methane. Reformers are assumed to cost about $350/kW and they are assumed to convert natural gas to hydrogen at with a conversion efficiency of about 75%.

Distributed Generation Fuel Prices and CHP Assumptions

<u>Natural Gas Prices</u>

Natural gas purchased for larger distributed generators is assumed to be at bulk/wholesale "city gate" prices, $3/MMBtu for this study (i.e., at substation locations). Natural gas purchased for smaller distributed generators is assumed to at retail prices, $5.60/MMBtu, for the evaluation (i.e., at feeder locations). (Source: Gas Research Institute Baseline Projection Data Book [2]).

<u>Diesel Fuel Prices</u>

Diesel fuel purchased for all distributed generators is assumed to have a price of $4.24/MMBtu [2].

Hydrogen Fuel Prices

Projecting hydrogen fuel prices is a problem given the present state of hydrogen production, transportation, and delivery infrastructure, and given the fact that at present there is virtually no market for hydrogen as a fuel. Based on the most recent estimates of hydrogen fuel production costs and assuming production and delivery scale-up, a price of $8/MMBtu delivered is assumed for this study (see above).

Cogeneration Cost and Value

Waste heat recaptured for use is assumed to be valued at the fuel cost not incurred, based on the aforementioned retail price of gas. It is assumed that if no waste heat from generation were available then natural gas would be burned in an 80% efficient boiler to create the equivalent heat. The cost of that gas is the benefit associated with combined heat and power. As noted above, the incremental cost associated with adding CHP capability to a distributed generator is assumed to be $250 per

Utility Operational and Avoided Cost Assumptions

Many of the assumptions (or underlying data used to derive assumptions) used for this study are shown in the table at the end of this section.

Load and Load Growth

Based on load data and projected load growth rate, total US load is assumed to be 780,000 MW in 1998. If escalated at 2.5%/year for 1999 2002 load will be about 882,000 MW by the end of 2002, and the load ***growth*** at 2.5% being 21,500 MW in 2002.

Peak Load Hours

For this study peak demand hours are defined as a typical summer peaking utility's highest 200 load hours. The significance is that a DR is assumed to provide "peaking service" if it can generate during those 200 hours.

Generation Capacity Cost

Generation capacity avoided costs assumed for the analysis are shown in Table A-3. The peaking resources reflect a range of costs from refurbishment/repowering of an existing peaker to purchase of low cost, inefficient additional combustion turbines possibly used equipment -to be used for peaking only. The baseload capacity values reflect a range of new combustion turbine based combined cycle plants to new clean coal boiler-based power plants. A triangular probability distribution for these costs is assumed.

Transmission and Distribution Canacitv Cost

Based on proprietary information used by DUA, a U.S. average of $27.5O/kW-year cost was assumed for distribution capacity needed to serve new electric load. $9.1 O/kW-year is assumed as the average cost for transmission capacity needed to serve new load. Also based on information proprietary to DUA, a statistical distribution is developed for these costs.

***Gen. Capacity** Avoided Cost*			
***1.a.** Base Load*			
FYI @ .115 FCR $500/kW => $57.5/kW-yr $800/kW => $92/kW-yr	Triangular Distribution	Low	70.0
		Mean	80.0
		High	90.0
***1.b.** Peaking*			
FYI @ .115 FCR $200/kW => $23/kW-yr $400/kW => $46/kW-yr	Triangular Distribution	Low	20.0
		Mean	30.0
		High	35.0

Units are $/kW-year

Table A-3: Baseload and Peaking Generation Capacity Costs

Electric Energy Cost

The assumed U.S. average utility marginal cost for electric energy during peak load hours is 4¢/kWh while annual average or baseload energy costs are assumed to be 2.5¢/kWh

System Load Factor and Annual Load Hours

The annual average load factor in the U.S. is assumed is .545. Annual full load equivalent hours (or full load hours) is .545 * 8760 hour per year = 4,774 annual load hours.

Line Losses

When transmitting electric energy through utility transmission and distribution (T&D) systems the resistivity of wires and transformers causes losses. These "resistive" or "I^2R" losses are assumed to be 3% on average throughout the U.S. In essence this means that to receive 1 kWh requires generation of 1.03 kWh upstream to make up for T&D-related energy losses.

Furthermore, losses are assumed to be higher during peak load hours, affecting "capacity losses" (or reduced ability to carry current). For the U.S. a 5% reduction in load carrying capability is assumed. That means that to get 1 kW of power to the customer during peak demand periods requires 1.05 kW of capacity.

Reliability Benefits Associated with Distributed Generation Use

The value of unserved energy (or value of service) and the total number of hours during the year that a customer cannot be served is a measure of the customers' "cost" of reliability." To the extent that this cost can be avoided by use of a distributed generator, that savings is a benefit that is assumed to accrue to the utility. The U.S. average value of service is assumed to be $3 per kWh "not served," and there are 1.4 hours per year of outages. Therefore, the reliability benefit from use of DRs is estimated to be $3 * 1.4 hours = $4.2 per kW-yr. of load.

Emissions Assumptions

Air emissions penalties (per unit of emissions) assumed for central generation and for distributed generators are shown in Table A-4.

NOx ($/lb.)	SOx ($/lb.)	CO ($/lb.)	CO_2 ($/lb.)	VOCs ($/lb.)	Particulate ($/lb.)
3.25	2.60	0.44	.011	2.65	2.0

Table A-4: Air Emission Economic Penalties, Applicable to All Generation Options

Air emissions in pounds per kWh generated, for central generation and for peak and baseload distributed generators using fossil fuels, are given in Table A-5. The resulting economic penalties in ¢/kWh are given in Table A-6.

Central Generation						
Generation Type	**NOx** (lbs./kWh)	**SOx** (lbs./kWh)	**CO** (lbs./kWh)	**CO_2** (lbs./kWh)	**VOCs** (lbs./kWh)	**Particulate** (lbs./kWh)
All	.0032	.0059	.002	1.00	.00014	.0031

Peak Load						
Distributed Generator Type	**NOx** (lbs./kWh)	**SOx** (lbs./kWh)	**CO** (lbs./kWh)	**CO_2** (lbs./kWh)	**VOCs** (lbs./kWh)	**Particulate** (lbs./kWh)
Microturbine	.00154	.00	.002	1.012	.00046	.00
Dual Fuel Engine	.00148	.00	.002	.9715	.00044	.00002
Combustion Turbine	.0016	.00	.002	1.144	.00048	.00
Diesel Engine	.002	.001	.0025	1.144	.0006	.00021

Base Load						
Distributed Generator Type	**NOx** (lbs./kWh)	**SOx** (lbs./kWh)	**CO** (lbs./kWh)	**CO_2** (lbs./kWh)	**VOCs** (lbs./kWh)	**Particulate** (lbs./kWh)
Microturbine	.00057	.00	.002	1.10	.00017	.00
Dual Fuel Engine	.00045	.00	.002	.88	.00014	.00
Combustion Turbine	.00046	.00	.002	.8896	.00014	.00
Solid Oxide Fuel Cell	.00	.00	.002	.90	.00	.00

Table A-5: Central and Distributed Generator Emissions, in Pounds per kWh of Generation

Air emissions in pounds per kWh generated, for peak and baseload distributed generators using hydrogen as fuel, are given in Table A-7. The resulting economic penalties in ¢/kWh are given in Table A-8.

Central Generation							
Generation Type	**NOx** (¢/kWh)	**SOx** (¢/kWh)	**CO** (¢/kWh)	**CO_2** (¢/kWh)	**VOCs** (¢/kWh)	**Particulate** (¢/kWh)	**Total** (¢/kWh)
All	1.07	1.58	.09	1.13	.04	.64	4.55

Peak Load							
Distributed Generator Type	**NOx** (¢/kWh)	**SOx** (¢/kWh)	**CO** (¢/kWh)	**CO_2** (¢/kWh)	**VOCs** (¢/kWh)	**Particulate** (¢/kWh)	**Total** (¢/kWh)
Microturbine	1.04	.00	.15	1.37	.03	.00	2.6
Adv. Turbine System (ATS)	.76	.00	.15	1.37	.03	.00	2.3
Small Frame CT	1.04	.00	.11	1.0	.03	.00	2.2
Dual Fuel Engine	3.25	.03	1.35	1.0	.27	.40	6.3
Diesel Engine	4.88	.08	1.31	.95	.53	.52	8.25
Spark/Gas Engine	1.01	.03	.35	1.02	.40	.36	3.2

Base Load							
Distributed Generator Type	**NOx** (¢/kWh)	**SOx** (¢/kWh)	**CO** (¢/kWh)	**CO_2** (¢/kWh)	**VOCs** (¢/kWh)	**Particulate** (¢/kWh)	**Total** (¢/kWh)
Microturbine	.46	.00	.14	1.21	.03	.00	1.8
Adv. Turbine System (ATS)	.39	.00	.12	.95	.03	.00	1.5
Frame Combustion Turbine	.44	.00	.13	1.16	.03	.00	1.75
Fuel Cell	.00	.00	.00	.89	.00	.00	.89
Solid Oxide Fuel Cell	.00	.00	.00	.89	.00	.00	.89
PEM Fuel Cell	.00	.00	.00	.80	.00	.00	.80

Table A-6. Central and Distributed Generation Emission Penalties

REFERENCES

1. Iannucci, J., Eyer, J., and Horgan, S.,"Gas Industry Utility Market Analysis," January 1996, report to the Gas Research Institute.
2. Baseline Proiection Data Book, Gas Research Institute, 1995.
3. Ogden, J. M., Dennis, E., Steinbugler, M., Strohbehn, J. W., "Hydrogen Energy System Studies," submitted to the National Renewable Energy Laboratory, prepared for the U. S. Department of Energy under contract #XR-11265-2, Jan. 18, 1995.