ENERGY AND ENVIRONMENTAL ANALYSIS, INC.

Advanced Microturbine System: Market Assessment

Submitted to:

Oak Ridge National Laboratory
Washington, DC

Final Report

May 2003

Submitted By:
Energy and Environmental Analysis, Inc.
1655 N. Fort Myer Drive, Suite 600
Arlington, Virginia 22209
(703) 528-1900

Table Of Contents

List Of Figures

List Of Tables

EXECUTIVE SUMMARY

The objective of this report is to provide the Department of Energy (DOE) with an integrated analysis of the economics and market potential for the advanced microturbine system (AMTS) that will provide product direction and quantify the market impact of the program. This report presents a composite picture of the market for microturbines based on the GE and Capstone development efforts and previous market analysis undertaken by the developers as part of the AMTS program.

The ultimate goals of the AMTS Program are to produce "ultra-clean, highly efficient" microturbine systems by fiscal year 2006 that can achieve the following performance targets:

- *High Efficiency*: Fuel to electricity conversion efficiency of at least 40%.
- *Environmental Superiority*: NOx emissions for gas-fired equipment lower than 7 parts per million in practical operating ranges.
- *Durability*: Designed for 11,000 hours of operation between major overhauls and a service life of at least 45,000 hours.
- *Economic Viability*: System costs lower than $500 per kilowatt, costs of electricity that are competitive with the alternatives (including grid connected power) for market applications, and capable of using a variety of fuels including natural gas, diesel, ethanol, landfill gas, and other bio-mass derived liquids and gases.

Table ES-1. AMTS Development Target Ranges

System Parameters	Units	Interim Development	AMTS Goals
Power	kW	200	270
Electric Efficiency (LHV)	%	34	40
Electric Efficiency (HHV)	%	30.6	36.0
List Package Price	$/kW	$650	$500
Maintenance Cost	$/kWh	$0.0160	$0.0110
Exhaust Temp. (Deg F)	Deg F	~500	~500
Recovered Heat for 135^{o} F Water (165 ^{o} F exhaust temperature)*	Btu/kW	4,200	3,100
Hot Water CHP Efficiency (HHV)	%	68.1	68.7
Recovered Heat Direct (to ambient)	Btu/kW	5,510	4,100
Direct CHP Efficiency (HHV)	%	80.0	79.1

Table ES-1 shows the package cost and performance targets for the AMTS as a product class – not for an individual machine. Two units are characterized: the first represents a near-term improvement in microturbine cost and performance and the second represents a system that meets all of the goals of the AMTS program.

Power – Power ranges for the AMTS will be between 200-270 kW. This size range reflects a significant increase in size compared to early market entry commercial microturbines.

Package Price – The package costs shown represent the manufacturer's selling price for the basic package. The total cost to the user will include additional costs such as engineering, installation, electric interconnection, and ancillary equipment.

Electric Efficiency – Electric efficiency is considerably higher than currently commercial microturbines.

Overhaul Period and O&M Costs – A key component of the operating and maintenance costs will be the planned period between overhauls. For the higher range of efficiency targets, the period of overhaul is expected be lower as a result of the use of special materials such as ceramics and because of the higher temperature environment. For intermediate efficiency products, the overhaul life is expected to be longer.

Useable Thermal Energy – Useable thermal energy for combined heat and power applications (CHP) is shown on the table for two configurations: a system that uses an air-to-water heat exchanger to provide hot water at 135^{o} F and a system that uses the exhaust directly into a process for heating or preheating. In the direct CHP case, the energy contained in the exhaust stream displaces ambient air. Therefore, the energy recovered and overall efficiencies are higher than in the hot water system where the heat of the exhaust is recovered only to 165^{o} F. In some applications, specifically as the heat source for an absorption chiller, the temperature requirements for hot water are higher – about 190^{o} F. The higher temperature requirements reduce the recoverable heat value shown in the table.

We analyzed three main types of power generation applications for the AMTS and several subtypes as listed below:

Combined Heat and Power

- Hot Water System –electricity and thermal energy in the form of hot water
- Direct Exhaust – electricity and direct use of exhaust in process heating needs.
- Integrated Energy System, Building Cooling, Heating and Power (IES-BCHP) using hot water and absorption cooling

Baseload Power Only

- Grid connected – continuous electricity production with no heat recovery
- Waste fuel utilization – electricity production from waste or unmarketable fuels such as remote oil and gas wells, landfill gas, coal seam gas

Peaking and Reliability

- Economic Peakshaving – electricity production for limited hours to reduce peak electricity costs

- Peakshaving plus reliability – peakshaving as above but with the ability to serve as the facility's emergency back-up generator.

Using a detailed industrial and commercial facility database, we undertook a screening of the technical market potential for each application by state and by business activity (SIC.) The resulting technical potentials were then further screened using the state-by-state average electricity and gas prices to determine the economic market share. **Table ES-2** summarizes the technical market potential and the economic market potential for each of the application/technology combinations considered.

Table ES-2   Summary of Economic Market Potential

Value Proposition	Technical Market Potential (MW)	Economic Market Potential			
		Interim Development		AMTS Goals	
		MW	Share	MW	Share
CHP New	10,520	640	6%	2,100	20%
CHP Retrofit	16,770	890	5%	2,700	16%
Direct CHP	3,370	440	13%	1,080	32%
IES-BCHP New	8,840	450	5%	1,270	14%
IES-BCHP Retrofit	8,650	380	4%	940	11%
Base (Retrofit plus New)	57,770	2,810	5%	7,840	14%
Waste Fuels/Oil Industry	2,630	2,630	100%	2,630	100%
Peaking	57,770	4,870	8%	8,250	14%
Peaking w Reliability	20,120	3,630	18%	4,450	22%

The results can be summarized as follows:

- Except for waste fuel applications, meeting the full AMTS goals provides 2-3 times the economic market of the interim development goals. This result underscores how critical it is for the AMTS to meet cost and performance design goals in order to move into a more broadly competitive position. (The remaining conclusions focus on the AMTS development goals system – final two columns of Table ES-2.)
- Traditional CHP is economic in 16% of the retrofit market and 20% of the new market representing 4,800 MW of potential AMTS sales.
- Direct CHP is more broadly applicable geographically than traditional CHP due to the lower costs and higher efficiency but has a lower capacity potential because the number of applications that can use direct exhaust is much more limited.
- IES-BCHP has a narrower geographic target market than traditional CHP, though applications within those regions are greater than for traditional CHP, so the economic market is 2,210 MW.

- Baseload power only is limited in terms of geographic target markets when compared to grid power. However, the very large number of facilities in the technical market potential suggests a market of 7,840 MW.
- Waste fuels and oil industry applications are applicable in all geographic regions where technical potential exists due to the very low fuel costs.
- Peaking applications are also limited geographically, but offer a very large number of potential applications and a correspondingly large economic market potential of 8,250 MW.
- Adding the reliability value to peaking broadens the geographic reach of the economic markets considerably. However, a smaller share of customers within each region has a technical need for both peakshaving and reliability.
- For applications that do not require matching to a thermal load in addition to the electric load, (baseload, peaking, peaking with reliability) there is a larger technical potential based simply on the larger number of such facilities. Discussions with both the equipment developers and with market developers have raised issues about the realism of penetrating these markets at such high levels.

The model results shown are based on the baseline technical assumptions described in the report. There are uncertainties in the ultimate technical performance and cost of the AMTS, system maintenance requirements, and future electric rates and gas rates. A sensitivity analysis of these factors shows a wide variation in potential market response. The future market for small on-site generation technology will also be affected by many other factors as follows:

- Utility Attitudes - While restructuring is opening access to the grid, and promises to provide open competition in the future, the local utility's attitude towards on-site generation will still affect the extent of market development during the transition. Utilities that have capacity or distribution constraints and see on-site generation as a potential solution will be attractive market entry targets.

- Competition with other DG technologies – The AMTS will compete not only with utility power but also with other DG technology such as internal combustion engines and fuel cells. If these other technologies can achieve competitive performance with the AMTS, then there will be competition for the market shares shown.
- Customer rate expectations – Initial customer expectations for electric rates to go down as a result of restructuring an are changing as a result of the California experience, deferring investment in technologies aimed at avoiding or reducing electric use. Customer interest in DG seems to be gaining momentum as a reliability and cost hedging tool.
- Rate Structures – Unbundling of rates into separately priced services will most likely reduce base load power costs and increase peak period prices. This will stimulate the

demand for peak shaving. On the other hand, some utilities have proposed rates that shift more of the distribution costs into fixed charges. This type of structure will reduce the economic benefits of on-site generation. Monitoring the evolution of rate structures in target markets and the extent and pace of rate unbundling and time of use rates will help identify priority markets and promising regions.

- Reliability – Perceptions of increased reliability problems after restructuring may increase the demand for customer generation for emergency and back-up purposes. Unbundling of rates may also quantify the cost of increased reliability allowing project economics to capture the benefits of enhanced reliability.
- Stranded Asset Recovery – The key factor in competitiveness of customer generation over the next 5-10 years is the level and means of stranded asset recovery. Whether or not a customer can avoid these charges by putting in self-generation will be an important factor in the marketability of generation systems during the transition periods. Stranded asset recovery will be implemented differently in each state. Political and regulatory efforts are needed to encourage regulators to provide exemptions for technology that is in the public interest.
- Standby/Back-up Rates - The cost of back-up service can be critical in determining the economic viability of on-site generation. Individual state PUCs; have been slow to realize the impact of these costs on the economics of self-generation. Market development in certain areas may depend on a restructuring of these rates.
- Peak Power Programs – Interest in interruptible or curtailable load programs that utilize customer generating equipment with utility notification or dispatch will likely increase in the future to help blunt the effect of price volatility in the wholesale power market, such as those that occurred during the past three summers. Current programs are designed and implemented by the utility. In the future, programs may be implemented either by the *independent system operator* coordinating the wholesale power transmission system or by private *energy service providers* aggregating small generators.
- Energy Service Providers – Utility marketing affiliates and independent energy service providers are in a frenzy to lock up customers and products to gain a market edge. Many unregulated service providers are developing multifunction portfolios that include power and fuel marketing, risk management, energy facilities management, and small power generation technology and marketing. During this period, these energy service providers are receptive to new product marketing ideas and opportunities.
- Interconnection - Interconnect requirements vary significantly in their complexity and ease of implementation. Efforts underway at the national and state level (New York, California, Texas) to standardize requirements, allow pre-certification or type testing of equipment and reduce interconnect application and contracting complexity could be significant factors in reducing costs for small generators.
- Environmental Regulations - Local interpretation of air quality regulations could impact the viability of small DG systems. Long-term pressure will be on DG to keep pace with Central Station power generation technology.

- Customer Perception - Microturbine and fuel cell developers have generated enormous interest about distributed generation among policymakers and potential users. While this attention has had a significant benefit in raising the visibility of this market in these early stages, failure of these new technologies to perform as promised could have negative effects on long-term market development.

SECTION 1 – INTRODUCTION

1.1 Objective

The objective of this report is to provide the Department of Energy (DOE) with an integrated analysis of the economics and market potential for the advanced microturbine system (AMTS) in order to provide product direction and to quantify the market impact of the program.

1.2 Background

DOE is pursuing a cooperatively funded, multi-path, technology development program called the *advanced microturbine system* (AMTS). The program consists of product development, materials and subsystem research, and supporting analyses. A requirement of the contracts awarded under the AMTS program was a quantification of technical market potential. Two product developers, General Electric and Capstone Turbine Corporation, undertook market and economic analysis to support the direction of their development efforts. Both companies provided summary reports to DOE as part of their contractual obligations.[1,2,3] . Energy Nexus Group (now a part of Energy and Environmental Analysis, Inc.) separately subcontracted under both GE Research and Development and Capstone to provide the detailed market and economic analysis that served as the primary resource for the summary reports.

In order to protect the proprietary nature of the individual company's technical and market planning, much of the detail of these analyses has been withheld from public release. To best support the overall AMTS program effort, DOE is interested in developing an integrated assessment of the AMTS market potential and economics that utilizes both the results of these two prior studies and also includes additional economic analysis and market characterization that reflects the goals and objectives of the overall DOE program effort rather than the confidential product evaluations of the individual developers.

This report presents a composite picture of the market for microturbines building on the prior GE and Capstone efforts. Specifically, new analysis has been undertaken as follows:

- Consistent definitions of market applications and product performance within these applications were developed.
- A revised and more detailed approach was developed to estimate the technical market potential in terms of number of sites and electric capacity. These assumptions include the methodology used to convert annual electric consumption to peak load, load shape, thermal energy requirements by major SIC market classification, and economic sizing within each application and value proposition. In addition, the determination of SIC code targets for each AMTS value proposition was reevaluated.

[1] *AMTS Market Study: U.S. DOE Cooperative Research and Development for Advanced Microturbine Systems*, prepared for Capstone Turbine Corporation, Onsite Energy Corporation, April 2001 (confidential and proprietary).
[2] *Commercial Implementation Plan for the Advanced Microturbine System (Draft)*, prepared for Capstone Turbine Corporation, Energy Nexus Group of Onsite Energy Corporation, March 2002 (confidential and proprietary).
[3] *Potential Technical Market of an Advanced Microturbine System, Draft Final Report*, prepared for GE Corporate Research & Development, Onsite Energy Corporation, March 2001 (confidential and proprietary).

- The economic market screening approach has been revised based on DOE AMTS program goals reflecting a general composite of the individual developer targets.

1.3 Report Organization

The report is organized into the following sections:

Section 2. Microturbine Systems – a discussion of current performance and development goals under the AMTS.

Section 3. Market Applications and Technical Potential – a description of the target markets for the AMTS and a quantification of the total size of the U.S. technical market potential.

Section 4. Economic and Market Analysis – a screening model that quantifies the U.S. economic market by state and by market application.

Section 5. Critical Market Development Factors – a qualitative discussion of market barriers and key issues.

SECTION 2 – ADVANCED MICROTURBINE SYSTEMS

2.1 Current Microturbine State-of-the-Art

Microturbines are very small combustion turbines with outputs of approximately 20 kW to 400 kW. A number of competing systems are under development with commercial production already initiated for several developers. Designed to combine the reliability of auxiliary power systems used on board commercial aircraft with the design and manufacturing economies of turbochargers, the units are targeted at CHP and prime power applications in commercial buildings and light industrial applications as well as special fuel applications such as oil and gas fields, biomass, and wastes.

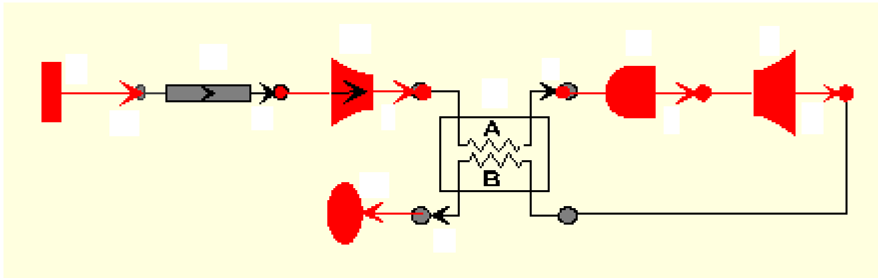
There is not a distinct size limit that distinguishes microturbines from small industrial gas turbines. However, several design features generally characterize microturbines:

- Radial flow compressors
- Low compression ratios (possibly two stage compression)
- No blade cooling
- Recuperation
- Low temperature materials that are amenable to low cost of production.

In most configurations, a high speed turbine (100,000 rpm) drives a high speed generator producing direct current (DC) or high frequency power that is electronically inverted to 60 Hz (or 50 Hz) AC. Current commercial microturbine systems are capable of producing power at around 25-33 percent efficiency by employing a recuperator that transfers exhaust heat back into the incoming air stream. The systems are air-cooled and some designs use air bearings, thereby eliminating both water and oil systems used by reciprocating engines. Low-emission combustion systems are being demonstrated which provide emissions performance comparable to larger combustion turbines. The potential for reduced maintenance and high reliability and durability remains to be demonstrated in a commercial environment.

Recuperated Cycle

In the recuperated cycle (**Figure 2.1**), turbine efficiency is increased by adding a recuperative heat exchanger, which uses the hot exhaust gas of the expansion turbine to preheat the air flowing into the combustor, thereby reducing the amount of fuel required. This cycle is also sometimes referred to as a regenerated cycle. There is no difference between these two designations from a thermodynamic viewpoint. A recuperator is a heat exchanger with passage walls through which heat flows by virtue of the temperature difference between the two fluids on either side of the wall. The fluids in a recuperator do not mix at all. A regenerator is a periodic heat exchanger in which hot and cold gas flow alternately in opposite directions through a matrix of fine passages. In a regenerator, the two fluids mix to a small degree, and leakage can occur from the high-pressure, compressor discharge side to the low-pressure, expansion turbine exhaust side.



Source: S. Freedman

Figure 2.1: Schematic of Recuperated Cycle

The recuperated turbine cycle produces about 10% less power than a simple cycle of the same compressor pressure ratio and turbine inlet temperature. This is because an inherent pressure drop is associated with the recuperator and with its connections to the engine and gas turbine exhaust. The design of a practical recuperated cycle involves balancing the tradeoffs among the parameters of efficiency, power, and cost. This is accomplished by analyzing various heat exchanger sizes, dimensions, and configurations to obtain a desired level of pressure drop on each side of the recuperator and interconnecting ducting, as well as analyzing recuperator cost. Similar tradeoffs apply to the regenerative cycle.

The exhaust of recuperated turbines gas turbines is lower in temperature due, respectively, to the use of recovered heat for preheating combustion. When generating thermal energy, these lower exhaust temperatures result in a somewhat lower amount of heat recovered and lower heat recovery efficiency.

2.2 Advanced Microturbine System Program

Changes in the electricity industry coupled with significant technology developments in small power generation options such as microturbines and fuel cells are opening potentially large market opportunities for distributed generation. Increasing competition for energy services at the retail level, continuing electric utility industry restructuring, increasing demand for electricity and concerns about reliability of supply, a recognition of the energy efficiency and reliability benefits of local generation, environmental movement toward pollution prevention and advancements in equipment are all factors which make distributed generation a serious option in the future generation mix of the United States.

As part of a larger Distributed Energy Resource strategy, the US Department of Energy (DOE) has initiated a multi-year development program focusing on microturbine systems that will culminate in the demonstration of an advanced system in the year 2006. The mission of the Advanced Microturbine System (AMTS) Program is to lead a national effort to design, develop, test, and demonstrate a new generation of fuel-flexible microturbine systems that will be cleaner, more efficient, more reliable, more durable, and more cost-effective than the current commercially available microturbine products.

As stated in the AMTS Program Plan, the ultimate goals of the AMTS Program are to produce “ultra-clean, highly efficient” microturbine systems by fiscal year 2006 that can achieve the following performance targets:

- *High Efficiency*: Fuel to electricity conversion efficiency of at least 40%.
- *Environmental Superiority*: NOx emissions for gas-fired equipment lower than 7 parts per million in practical operating ranges.
- *Durability*: Designed for 11,000 hours of operation between major overhauls and a service life of at least 45,000 hours.
- *Economic Viability*: System costs lower than $500 per kilowatt, costs of electricity that are competitive with the alternatives (including grid connected power) for market applications, and capable of using alternative fuels including natural gas, diesel, ethanol, landfill gas, and other bio-mass derived liquids and gases.

The AMTS Program's goals are consistent with overall goals set forth in the Comprehensive National Energy Strategy "to improve the efficiency of the energy system, ensure against disruptions, promote energy production and use in ways the respect health and environmental values and expand energy choices."

2.3 Advanced Microturbine System Performance Targets

Table 2-1 shows the package cost and performance targets for the AMTS as a product class – not for an individual machine. The ranges shown include the variation among developers, variations for multiple products under development, and uncertainty ranges for individual products.

Table 2-1. AMTS Development Target Ranges

System Parameters	Units	Performance Targets
Power	kW	200-270
Electric Efficiency (LHV)	%	34 – 41.5%
Electric Efficiency (HHV)	%	30.6 – 37.4
List Package Price	$/kW	$500 – $670
Overhaul Life/Service Life	Hours	11,000 / 45,000
Maintenance Cost	$/kWh	$0.010 – $0.017
Exhaust Temp. (Deg F)	Deg F	~500
Recovered Heat for 135^{o} F Water*	Btu/kW	2,700 – 4,200
Hot Water CHP Efficiency (HHV)	%	68 – 76%
Recovered Heat Direct (to ambient)	Btu/kW	3,600 – 5,500
Direct CHP Efficiency (HHV)	%	80 – 86%

*Assumes a 165^{o} F. exhaust exit temperature

Power – Power ranges for the AMTS will be between 200-270 kW. This size range reflects a significant increase in size compared to early market entry commercial microturbines – a factor of 2 to 10 times larger.

Package Price – Target package costs shown represent the manufacturer's selling price for the basic package. The total cost to the user will include additional costs such as engineering, installation, electric interconnection, and ancillary equipment. The costs associated with these other factors vary by application and are addressed in detail in the next section.

Electric Efficiency – Electric efficiency targets are considerably higher than currently commercial microturbines. The efficiency values in the table are provided on both a lower heating value and a higher heating value basis assuming natural gas is the fuel. LHV, which excludes the heat of condensation for the water vapor contained in the exhaust, is the standard rating measurement for engine and turbine manufacturers. HHV, which includes the full heat content of the water vapor, is used as the sales measurement ($/MMBtu) for natural gas. Therefore, LHV is the appropriate measure of engine efficiency while HHV is properly used in economic analysis of the effectiveness of the use of purchased fuels.

Overhaul Period and O&M Costs – A key component of the operating and maintenance costs will be the planned period between overhauls. For the higher range of efficiency targets, the period of overhaul is expected be lower than the target goal as a result of the use of special materials such as ceramics and because of the higher temperature environment. For intermediate efficiency products, the overhaul life is expected to be longer than the target.

Useable Thermal Energy – Useable thermal energy for combined heat and power applications (CHP) is shown on the table for two configurations: a system that uses an air-to-water heat exchanger to provide hot water at 135^{o} F and a system that uses the exhaust directly into a process for heating or preheating. In the direct CHP case, the energy contained in the exhaust stream displaces ambient air. Therefore, the energy recovered and overall efficiencies are higher than in the hot water system where the heat of the exhaust is recovered only to 165^{o} F. In some applications, specifically as the heat source for an absorption chiller, the temperature requirements for hot water are higher – about 190^{o} F. The higher temperature requirements reduce the recoverable heat value shown in the table.

SECTION 3 – MARKET APPLICATIONS AND TECHNICAL MARKET POTENTIAL

The previous section describes the basic parameters of the AMTS system. However, the actual performance of these systems in different applications depends not only on the package cost and performance but also on the needs of the application. These needs determine the operating mode of the system, hours of operation, the degree of heat recovery obtained, the emissions requirements, and the ancillary equipment required. All of these factors combine to determine the economic competitiveness of the system in each application.

3.1 Analytical Approach

The technical market potential was estimated based on the identification of sites that could provide the necessary electric and thermal load consumption and load shapes that fit with the requirements of each application. The approach used in this analysis included applications analysis, cost and performance modeling, technical market screening by size, application, and state, a state-by-state economic market screen based on the average price paid for electricity and gas for customers in the size range appropriate for the AMTS.

Applications Analysis

For this study and previous studies, we analyzed three primary types of power generation applications for the AMTS and several subtypes as listed below:

Combined Heat and Power
- Hot Water System
- Direct Exhaust
- Integrated Energy System, Building Cooling, Heating and Power (IES-BCHP) using hot water

Baseload Power Only
- Grid connected
- Waste fuel utilization
- Oil and gas industry

Peaking and Reliability
- Economic Peakshaving
- Peakshaving plus reliability

The analysis of each application was based on a number of factors:
- Prior engineering experience with DG installations
- Energy consumption databases that provide information on electricity consumption, gas consumption by end-use, region, business application, and facility size
- Cost and performance model of the AMTS

- Assessment of sizing and operating strategies that would produce the best economic outcome in most applications
- Review of existing applications.

A key part of the applications analysis was the determination of the application energy requirements. Two proprietary models were utilized for this purpose:

- eShapes[4] – Hourly electric demand and daily gas consumption for 19 building prototypes (i.e., hospital, supermarket, restaurant, office) in 10 geographical regions. Output is in the form of prototype applications of specific size or by square foot, but the unit values are fixed so it is not useful to evaluate applications that of a significantly larger or smaller size than the prototype applications. From the model output it is possible to calculate peak electric load, annual consumption, load factor, and seasonal and diurnal variations. An assumption was made about the daily gas consumption that it was distributed evenly throughout the day. This simplifying assumption was used to estimate the degree of utilization of the available thermal output from a CHP system of any given size. The model provides no end-use detail (such as air conditioning, water heating, space heating), only energy consumption. In order to analyze integrated energy systems with thermally activated cooling systems, the temperature sensitive load was inferred by comparing the minimum daily load to the maximum load for each day of the week.
- eQuest[5] – is an open source model developed as an accessible tool for California energy consumers and funded by the California public electric utility industry. The model is a DOE-2 based building energy simulation model. There are 18 defined building/application prototypes. Other applications can be modeled by changing the parameters. For example, it is possible to substitute an absorption chiller for electric cooling, to change the occupancy schedule, or make any other change to the building, the usage patterns, the mechanical systems, or the energy efficiency levels. eQuest was used to identify applications that made good CHP targets and to define the optimal sizing with respect to the facility peak load, and to evaluate the addition of thermally activated cooling to an AMTS based integrated energy system. The model can be run for any site for which DOE-2 weather data exists.

The results of the applications analysis consist of the following information needed to define market potential:

1. Additional equipment needed for the application (cost and performance)
2. Installation costs
3. Thermal energy available and thermal energy utilized
4. Target business types (standard industrial classifications) that could support the operating requirements of the system, and
5. Appropriate AMTS sizing criteria relative to the application energy consumption and peak load.

Economic Performance (Value Proposition)

The economic performance of the AMTS was estimated for each application. The system developers provided the basic operating cost and performance characteristics. From the system

[4] eShapes™, Regional Energy Research, Inc., San Diego, California.
[5] eQuest™ 2.5, James J. Hirsch and Associates.

exhaust temperature and mass flow, we developed estimates of available thermal energy for three different types of applications (production of 135^o F hot water, direct process use of exhaust, and operation of an absorption chiller using 190^o F hot water.) The cost of necessary heat recovery equipment was based both on information provided by the developers and from vendor quotes. A simple discounted cash flow model was used to define net power costs from the system (on a revenue requirements basis) to provide a static comparison of system performance within and between applications. Net power costs define the cost of power to the facility operator after credit is applied for thermal energy utilization. A payback model was used in the economic market screen to determine the economic acceptance on a state-by-state basis of the AMTS for each application (i.e., CHP, baseload power) based on the prevailing energy prices in the state.

Technical Market Screen

Based on the SIC targets and application requirements defined in the *applications analysis,* Energy Nexus searched MarketPlace, a comprehensive, proprietary database of over 14 million business facilities.[6] MarketPlace allows the sorting and selection of this business data using a large number of screens. The screens used for this analysis consisted of 2-digit and 4-digit SIC, electricity consumption, natural gas consumption, and state. The energy use estimations in the model are from the D&B Energy Demand Estimators that are derived from actual consumption data from a partnership alliance consisting of 10 utility firms, 12-month state temperature patterns, and D&B's demographic database of over 13 million US businesses.

The energy data in the database consist of consumption ranges only. Therefore, the applications analysis was used to determine for each consumption range in the MarketPlace database, what that meant in terms of the facility peak load, and what capacity DG system that could support. The database contains 163,000 facility records that have electric consumption large enough to support an AMTS DG system between 200 and 2,000 kW. An additional screen for CHP systems was used in that the facility had to have natural gas consumption that was at least large enough to support the thermal utilization specified for the application. **Table 3.1** shows how the sizing methodology was applied for combined heat and power (CHP.)

Table 3.1 Summary of MarketPlace Screening for CHP Target 2-digit SICs

Electric Cons. Bin MWh/year	Data Records	Gas Cons. MMBtu/yr	CHP System Size kW* Min.	Max.	Avg.	CHP Potential Sites	MW
No electric data	1,595,810	Outside of AMTS Screening Range					
Less than 1,000	12,212,084						
1,000 to 2,499	107,254	>2,500	114	285	200	26,610	5,314
2,500 to 4,999	36,237	>5,000	285	571	428	9,955	4,261
5,000 to 9,999	14,246	>10,000	571	1,141	856	4,720	4,041
10,000 to 24,999	5,467	>25,000	1,142	2,854	1,998	1,572	3,140
More than 25,000	1,695	Outside of AMTS Screening Range					
					Total Potential	**42,857**	**16,757**

* Facility Load Factor 60%, CHP Sizing 60% of peak load

The MarketPlace data were used for the estimation of existing or retrofit applications. For new applications, we estimated the 20-year growth rate for each 2-digit SIC based on the five-year

[6] MarketPlace, D&B Solutions.

growth rate (1992-1997) as reported by the U.S. Census of Manufactures. We used the average of growth in employment and real value of shipments. **Table 3.2a and 3.2b** show these data for the manufacturing sector (part a) and the commercial sector (part b.) In cases where data were missing or withheld, the 20-year market growth was estimated. In cases, where the growth rate was negative, no new applications were assumed. The 20-year estimates (final column) were multiplied by the existing market in each 2-digit SIC to derive the new market estimate.

Table 3.2a Estimation of 20-Year New Market Growth by SIC: Manufacturing Sector

SIC	1987 SIC Description	Value of Shipments ($1000)			Paid Employees			20-Year	20-year Est.
		1997	1992	%chgReal	1997	1992	% chg	Avg. Growth	Growth
20	Food	4.81E+08	4.07E+08	3.28%	1.56E+06	1.50E+06	3.9	15.16%	15.16%
21	Tobacco	n.a.	3.52E+07	n.a.	n.a.	3.80E+04	n.a.	n.a.	0.00%
22	Textile	8.24E+07	7.08E+07	1.81%	5.62E+05	6.16E+05	-8.8	-13.27%	0.00%
23	Apparel	8.12E+07	7.17E+07	-0.95%	8.29E+05	9.85E+05	-15.8	-29.53%	0.00%
24	Lumber	1.12E+08	8.16E+07	19.96%	7.57E+05	6.56E+05	15.5	92.10%	92.10%
25	Furniture	6.15E+07	4.38E+07	22.72%	5.24E+05	4.71E+05	11.2	87.14%	87.14%
26	Paper	n.a.	1.33E+08	n.a.	n.a.	6.26E+05	n.a.	n.a.	10.49%
27	Printing	2.11E+08	1.66E+08	10.97%	1.53E+06	1.49E+06	2.8	30.51%	30.51%
28	Chemicals	4.00E+08	3.05E+08	14.51%	8.20E+05	8.49E+05	-3.3	24.37%	24.37%
29	Petroleum	1.76E+08	1.50E+08	2.28%	1.06E+05	1.14E+05	-7.2	-9.48%	0.00%
30	Rubber	1.61E+08	1.14E+08	23.69%	1.04E+06	9.07E+05	14.4	100.85%	100.85%
31	Leather	n.a.	9.69E+06	n.a.	n.a.	1.01E+05	n.a.	n.a.	10.49%
32	Stone, Clay, and Glass	8.72E+07	6.25E+07	21.98%	5.05E+05	4.69E+05	7.8	74.24%	74.24%
33	Primary Metals	1.89E+08	1.38E+08	19.33%	6.92E+05	6.62E+05	4.5	56.87%	56.87%
34	Fabricated Metals	2.32E+08	1.67E+08	21.62%	1.55E+06	1.36E+06	13.7	91.66%	91.66%
35	Machinery	4.07E+08	2.59E+08	37.68%	1.98E+06	1.74E+06	13.8	149.96%	149.96%
36	Electronic Equipment	3.49E+08	2.17E+08	40.56%	1.58E+06	1.44E+06	10	146.35%	146.35%
37	Transportation Equip.	5.16E+08	3.99E+08	12.94%	1.56E+06	1.65E+06	-5.2	16.41%	16.41%
38	Instruments	n.a.	1.35E+08	n.a.	n.a.	9.07E+05	n.a.	n.a.	43.11%
39	Miscellaneous Mfg.	5.10E+07	3.95E+07	12.86%	3.94E+05	3.65E+05	7.8	48.19%	48.19%

Source: http://www.census.gov/epcd/ec97sic/E97SUS.HTM

Table 3.2b Estimation of 20-Year New Market Growth by SIC: Commercial Sector

SIC	1987 SIC Description	Value of Shipments ($1000) 1997	1992	%chgReal	Paid Employees 1997	1992	% chg	20-Year Avg.Growth	20-year Est. Growth
41	Passenger Transportation	n.a.	1.26E+07	n.a.	(100,000+)	3.55E+05	n.a.	n.a.	4
42	Motor Freight Transportation	1.97E+08	1.44E+08	19.99%	1.96E+06	1.58E+06	24.1	121.85%	12
44	Water Transportation	3.52E+07	2.92E+07	5.29%	1.79E+05	1.71E+05	4.2	20.37%	2
45	Air Transportation	4.74E+07	n.a.	n.a.	3.62E+05	n.a..	n.a.	n.a.	4
46	Pipelines, except Natural Gas	7.21E+06	7.06E+06	-10.77%	1.35E+04	1.68E+04	-19.6	-48.25%	0
47	Transportation Services	n.a.	2.39E+07	n.a.	(100,000+)	3.29E+05	n.a.	n.a.	4
48	Communications	3.49E+08	2.31E+08	32.33%	1.45E+06	1.29E+06	12	122.72%	12
49	Electric, Gas, and Sanitary Services	4.48E+08	3.11E+08	25.91%	8.36E+05	9.15E+05	-8.6	39.38%	3
50	Wholesale Trade - Durable Goods	2.30E+09	1.59E+09	26.11%	3.89E+06	3.35E+06	16.1	115.11%	11
51	Wholesale Trade - Nondurable Goods	1.94E+09	1.64E+09	2.89%	2.62E+06	2.44E+06	7.4	22.23%	2
52	Building Materials, Hardware Supply	1.46E+08	9.88E+07	29.32%	8.30E+05	6.66E+05	24.7	160.22%	16
53	General Merchandise Stores	n.a.	2.45E+08	n.a.	(100,000+)	2.08E+06	n.a.	n.a.	8
54	Food Stores	4.16E+08	3.69E+08	-1.49%	3.11E+06	2.97E+06	4.7	6.57%	6
55	Auto Dealers and Gas Service Stations	7.88E+08	5.30E+08	30.04%	2.28E+06	1.94E+06	17.6	135.05%	13
56	Apparel and Accessory Stores	1.17E+08	1.02E+08	0.22%	1.12E+06	1.14E+06	-2.5	-4.48%	0
57	Home Furniture Stores	1.36E+08	9.32E+07	27.64%	8.62E+05	7.02E+05	22.7	145.46%	14
58	Eating and Drinking Places	n.a.	1.95E+08	n.a.	(100,000+)	6.55E+06	n.a.	n.a.	8
59	Miscellaneous Retail	3.66E+08	2.61E+08	22.35%	2.80E+06	2.36E+06	18.6	110.67%	11
60	Depository Institutions	n.a.	5.32E+08	n.a.	(100,000+)	2.10E+06	n.a.	n.a.	7
61	Nondepository Credit Institutions	n.a.	1.35E+08	n.a.	(100,000+)	4.46E+05	n.a.	n.a.	7
62	Securities and Commodities Brokers	n.a.	1.09E+08	n.a.	(100,000+)	4.06E+05	n.a.	n.a.	7
63	Insurance Carriers	9.97E+08	7.96E+08	9.53%	1.61E+06	1.52E+06	6.4	35.88%	3
64	Insurance Agents and Brokers	7.53E+07	5.17E+07	27.39%	7.13E+05	6.36E+05	12.2	105.93%	10
65	Real Estate	1.80E+08	1.42E+08	11.10%	1.34E+06	1.23E+06	8.8	46.15%	4
67	Holding and other Investment Offices	1.39E+08	6.58E+07	84.15%	2.58E+05	1.74E+05	48.3	663.42%	66
70	Hotels	9.79E+07	6.92E+07	23.65%	1.69E+06	1.49E+06	13.2	96.69%	9
72	Personal Services	5.31E+07	4.33E+07	7.32%	1.30E+06	1.22E+06	7	31.85%	3
73	Business Services	5.29E+08	2.75E+08	68.06%	8.65E+06	5.54E+06	56.1	590.15%	59
75	Auto Repair	9.96E+07	7.00E+07	24.29%	1.09E+06	8.64E+05	26.7	148.03%	14
76	Miscellaneous Repair	3.73E+07	3.07E+07	6.10%	4.19E+05	4.28E+05	-2.2	8.04%	8
78	Motion Pictures	6.79E+07	4.40E+07	35.13%	5.71E+05	4.78E+05	19.5	162.75%	16
79	Amusement and Recreation Services	8.18E+07	4.88E+07	46.65%	1.23E+06	9.00E+05	36.9	304.04%	30
80	Health Services	3.99E+08	2.99E+08	16.48%	5.52E+06	4.45E+06	24	71.74%	7
81	Legal Services	1.23E+08	1.01E+08	6.00%	9.56E+05	9.24E+05	3.5	20.40%	2
82	Educational Services	1.24E+07	7.24E+06	50.14%	1.89E+05	1.33E+05	41.5	22.02%	2
83	Social Services	7.57E+07	5.37E+07	23.26%	1.59E+06	1.41E+06	12.7	93.75%	9
84	Museums, Botanical Gardens, etc.	6.28E+06	3.20E+06	71.56%	8.44E+04	6.63E+04	27.3	398.59%	39
86	Membership Organizations	2.00E+06	n.a.	n.a.	2.52E+04	n.a.	n.a.	n.a.	10
87	Professional Services	3.02E+08	1.93E+08	36.91%	2.93E+06	2.27E+06	29.1	212.97%	21
89	Services, not elsewhere classified	n.a.	7.97E+06	n.a.	n.a.	8.11E+04	n.a.	n.a.	20

Economic Market Screen

The technical potential defines applications for which it is physically possible for AMTS system to meet the electric and thermal load requirements. Economic screening of the technical market potential was conducted using a state-by-state screen of electricity and gas prices. A market acceptance factor was defined that is a function of the economic payback period for the AMTS.

The remainder of this section describes the value propositions, the types of facilities where they are applicable and the results of the technical market potential screening. The technical market potential is an estimation of market size constrained only by technological limits—the ability of AMTS technologies to fit existing customer energy needs. The technical potential includes sites that have the energy consumption characteristics that could apply the AMTS system. The technical market potential does not consider screening for other factors such as ability to retrofit, owner interest in applying CHP or on-site generation, capital availability, natural gas availability, and variation of energy consumption within customer application/size class. All of these factors affect the feasibility, cost and ultimate acceptance of CHP at a site and are critical in the actual economic implementation of CHP. A first cut economic market screening is described in *Section 4.*

3.2 Combined Heat and Power

Combined Heat and Power (CHP) provides the best economic value to customers that are grid connected because the AMTS provides both electric and thermal needs for the site. The AMTS is capable of providing thermal energy either through a heat recovery boiler that provides hot water/low-pressure steam or through the direct utilization of the turbine exhaust. Hot water systems can be further broken down into those that provide hot water/heating only and those that utilize the hot water to provide cooling/dehumidification.

Hot Water CHP

Traditional CHP applications exist in commercial, institutional, and industrial markets for the simultaneous production of heat and power from a compact package. The optimal value from CHP systems requires a steady-state operation with a high load factor and a steady thermal load on site to provide an economic use for the recoverable heat. The systems usually operate in parallel with the utility and require supplementary and back-up power. In the commercial sector, applications such as hotels, hospitals, health clubs, water parks, and laundries provide both a high electric load factor and a steady thermal requirement.[7] In most commercial applications, the thermal requirements are in the form of hot water – an ideal match for the AMTS. In the industrial sector, there are wide ranges of industries that require thermal and electric energy year-round. Many industries, though, require high-pressure steam that cannot be produced by the AMTS. Industries that require low temperature heating such as for wash water or other needs would fit in well with the AMTS. The largest number of small CHP industrial applications have been in food, chemicals, paper, lumber, and miscellaneous manufacturing processes.

Table 3.3 compares the installed cost and performance of the AMTS for a system that achieves the AMTS goals and for a higher cost, less efficient system that we have identified as *Interim Development* or *Partial Success.* The interim development goals represent a system that might

[7] *Appendix B* details the operating CHP plants installed up to 2000 in both the industrial and commercial sectors.

enter the market within a few years that does not yet meet all of the AMTS program goals. The two systems are designed to show how the market will respond to cost and performance improvement. For each of these systems, installed cost is estimated for both a retrofit application and for a new facility. Retrofit applications incur higher installation costs due to the need to design the heat recovery system within the confines of the existing equipment and space. The cost and performance factors are based on a composite of developer estimates; they are not intended to represent a specific technology or project. Installation costs represent a forward-looking view to a streamlined, competitive DG industry with full regulatory support. Current installation costs for projects of similar size are much higher.

Table 3.3. CHP Installed Cost, Performance, and Net Power Costs

System Parameter	Units	Interim Development		AMTS Goals	
Cost and Performance		Retrofit	New	Retrofit	New
Capacity	kW	200	200	270	270
List Price	$/kW	$650	$650	$500	$500
Heat Recovery	$/kW	$350	$210	$278	$167
Installation	$/kW	$325	$325	$293	$293
Capital Cost New	$/kW	$1,325	$1,185	$1,071	$959
O&M Cost	$/kWh	$0.0160	$0.0160	$0.0110	$0.0110
Heat Rate (HHV)	Btu/kWh	11,154	11,154	9,481	9,481
Electric.Gen. Eff. (LHV)	%	34.0%	34.0%	40.0%	40.0%
Electric.Gen. Eff. (HHV)	%	30.6%	30.6%	36.0%	36.0%
Exhaust Temperature	Degree F	500	500	500	500
Heat Recovered	Btu/kWh	4,188	4,188	3,102	3,102
Net Heat Rate	Btu/kWh	5,918	5,918	5,603	5,603
Overall Efficiency	%	68.1%	68.1%	68.7%	68.7%
Operating Parameter					
Annual Capacity Factor	%	80%	80%	80%	80%
Cost of Capital	%	10%	10%	10%	10%
Thermal Utilization Factor	%	80%	80%	80%	80%
Avoided Thermal Process Eff.	%	80%	80%	80%	80%
Fuel Cost $/MMBtu	$/MMBtu	$6.50	$6.50	$6.50	$6.50
Net Power Costs	$/kWh	$0.0920	$0.0888	$0.0773	$0.0747

Figure 3.1 compares the net power costs for these systems graphically. *Net Power Costs* are

defined as the cost of power from the AMTS required to earn a 10% return over a 10-year economic life after the value of the thermal energy is subtracted. The system is assumed to run at an 80% load factor (7,000 hours/year) and that 80% of the available thermal energy is used productively – avoiding the need to fire an 80% efficient gas-fired boiler. The gas price of $6.50/MMBtu reflects the average price of gas to commercial and industrial customers that purchase gas from local gas distribution companies.[8]

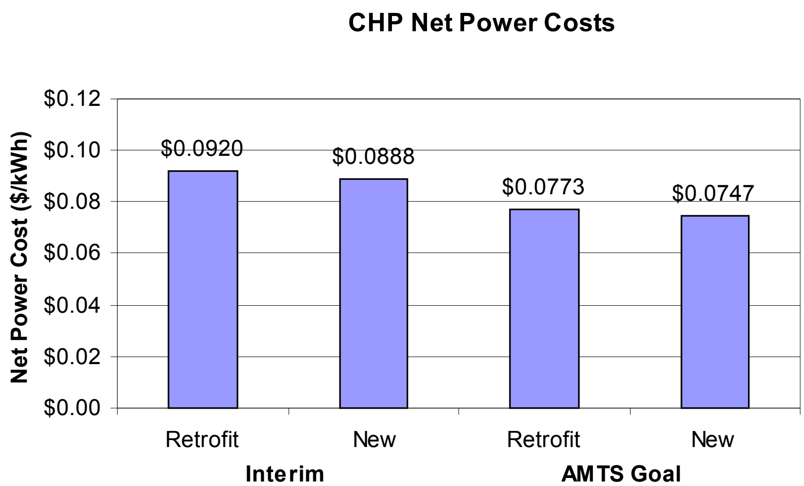


Figure 3.1. Comparison of AMTS CHP Net Power Costs

These net power costs are illustrative. In *Section 4*, the AMTS net power costs are compared using the average electric and gas prices for each state to determine a state-by-state economic market potential.

Typical applications for traditional CHP are shown in Table 3.4 and 3.5.

[8] Energy Information Administration Online Database, Weighted Average of monthly figures from July 2000 through June 2001.

Table 3.4 CHP Target Applications - Commercial, Existing Technology

Application	CHP System Size	Thermal Demand
Hotels/Motels	100 kW- 1+ MW	Domestic hot water, space heating, pools
Nursing Homes	100 – 500 kW	Domestic hot water, space heating, laundry
Hospitals	100 kW – 5+ MW	Domestic hot water, space heating, laundry
Schools	50 – 500 kW	Domestic hot water, space heating, pools
Colleges/Universities	300 kW – 30 MW	Centralized space heating, domestic hot water
Commercial Laundries	100 – 800 kW	Hot water
Car Washes	100 – 500 kW	Hot water
Health Clubs/Spas	50 – 500 kW	Domestic hot water, space heating, pools
Country/Golf Clubs	100 kW – 1 MW	Domestic hot water, space heating, pools
Museums	100 kW – 1+ MW	Space heating, domestic hot water
Correctional Facilities	300 kW – 5 MW	Space heating, domestic hot water
Water Treatment/Sanitary	100 kW – 1 MW	Process heating
Large Office Buildings*	100 kW – 1+ MW	Space heating, domestic hot water
Apartment Buildings	50 kW – 1+ MW	Domestic hot water, space heating

* > 100, 000 square feet

Table 3.5 Target Industrial CHP Applications

SIC	Application	E/T Ratio	Thermal Demand
20	Food Processing	0.4-1.0	Hot water, low pressure steam
22	Textiles	0.5-1.5	Hot water, low pressure steam
24	Lumber/Wood	2.0-5.0	Low pressure steam, direct heat
25	Furniture	1.5-3.0	Low pressure steam, direct heat
26	Paper Products	0.8-2.0	Medium - high pressure steam
28	Chemicals	0.4-1.0	Low - high pressure steam
30	Rubber/Plastic Products	1.0-3.0	Low pressure steam, direct heat
33	Primary Metals	0.5-4.0	Medium-high pressure steam
34	Fabricated Metals	0.75-3.0	Low pressure steam, direct heat
35	Machinery	2.0-4.0	Hot water, low pressure steam
37	Transportation Equipment	1.2-2.2	Hot water, low pressure steam
38	Instruments	1.0-2.5	Hot water, low pressure steam
39	Misc Manufacturing	2.0-4.0	Hot water, low pressure steam

Based on the MarketPlace market screening described at the beginning of this section the technical potential for the traditional CHP markets are shown in **Table 3.6**. The screening was conducted on all of the agriculture, mining, construction, and manufacturing SIC codes for facilities that had electricity and natural gas consumption sufficient to support a CHP system within the AMTS screening size range of 200 to 2,000 kW. In the commercial and institutional sectors, hotels, health clubs and other personal services, recreational facilities, health services, educational services, social services, and prisons were included. The retrofit market is based on the existing stock of business and institutional establishments. The *20-Year new* market is based on the observed '92-'97 average growth in employees and output by 2-digit SIC. For many agricultural, mining, and manufacturing sectors, the economic activity is declining. For these sectors the new market was assumed to be zero.

Table 3.6. Technical Market Potential for Traditional CHP

Market	Units in each Size Bin Average Size				Total Capacity
	200 kW	430 kW	860 kW	2,000 kW	MW
Retrofit	26,610	9,955	4,720	1,572	16,768
20-Year New	18,651	6,553	2,797	797	10,516

There is a large technical potential for traditional hot water CHP. However, prior to the commercial introduction of microturbines, only about 1,000 sites less than 1,000 kW in size have installed CHP in the last 20 years. This amount represents an average penetration of only 50 units per year. Current technology microturbine sales have more than doubled the cumulative market, but to achieve the high levels of market penetration envisioned for the future will require a concentrated effort encompassing technology development, project development, and elimination of market barriers.

Direct CHP

The exhaust from the AMTS (as well as from many current microturbines) has several characteristics that make it suitable for direct use in processes or for boiler or process air preheat: very low levels of criteria pollutants, no hazardous chemicals, no lube oil, and a high oxygen content. The exhaust is cleaner than the mixture of air and combustion products in a direct gas-fired oven. Where it is feasible to use the exhaust directly, the cost of the heat recovery boiler is avoided, reducing capital costs and effective net power costs. In addition, a hot water CHP system captures the heat content of the exhaust from its exit temperature down to a set temperature to provide a given temperature of hot water – in hot-water CHP the exhaust is brought down to 165^{o} F. to provide 135^{o} F. hot water. The direct utilization of exhaust displaces the use of fuels for heating air from ambient. Therefore, the value of the thermal energy provided by a direct CHP system is the total sensible heat content from the exhaust exit temperature to ambient conditions. The latent heat of vaporization in the exhaust is not recovered, just as it is not recovered in displaced process application. **Table 3.7** and **Figure 3.2** show the cost and performance and net power costs for direct CHP. There was no cost distinction for direct CHP between new and retrofit applications.

Table 3.7. Direct CHP Installed Cost, Performance, and Net Power Costs

Direct CHP	Units	Interim	AMTS Goals
Cost and Performance			
Capacity	kW	200	$270
List Price	$/kW	$650	$500
Heat Recovery	$/kW	$105	$83
Installation	$/kW	$325	$293
Capital Cost New	$/kW	$1,080	$876
O&M Cost	$/kWh	$0.0160	$0.0110
Heat Rate (HHV)	Btu/kWh	11,154	9,481
Electric.Gen. Eff. (LHV)	%	34.0%	40.0%
Electric.Gen. Eff. (HHV)	%	30.6%	36.0%
Exhaust Temperature	Degree F	500	500
Heat Recovered	Btu/kWh	5,513	4,084
Net Heat Rate	Btu/kWh	4,262	4,376
Overall Efficiency	%	80.0%	79.1%
Operating Parameters	Same as CHP		
Net Power Costs	$/kWh	$0.0750	$0.0642

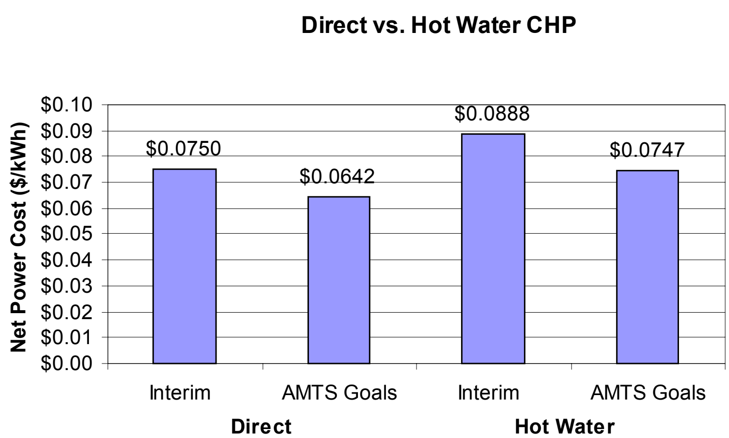


Figure 3.2. Comparison of AMTS Direct and Hot Water CHP Net Power Costs

Table 3.8. SIC Codes for Direct CHP Value Proposition

Industrial					
20		**Food and Kindered**	**29**		**Petroleum Refining**
	2043	Cereal breakfast foods		2911	Petroleum refining
	2044	Rice milling		2951	Asphalt paving mixtures and blocks
	2048	Prepared feeds, nec	**30**		**Rubber and Plastic**
	2051	Bread, cake, and related products		3081	Unsupported plastics film and sheet
	2062	Cane sugar refining		3084	Plastics pipe
	2068	Salted and roasted nuts and seeds		3085	Plastics bottles
	2074	Cottonseed oil mills		3089	Plastics products
	2075	Soybean oil mills	**32**		**Stone, Clay, Glass and Concrete**
	2095	Roasted coffee		3211	Flat glass
	2096	Potato chips and similar snacks		3229	Pressed and blown glass
21		**Tobacco Products**		3271	Concrete block and brick
	2141	Tobacco stemming and redrying	**33**		**Primary Metals**
22		**Textile Mills**		3312	Blast furnaces and steel mills
	2211	Broadwoven fabric mills, cotton		3321	Gray and ductile iron foundries
24		**Lumber and Wood Products**		3325	Steel foundries
	2436	Softwood veneer and plywood	**34**		**Fabricated Metal**
26		**Paper and Allied Products**		3411	Metal cans
	2631	Paperboard mills	**36**		**Electronic Equipment**
28		**Chemicals**		3621	Motors and generators
	2823	Cellulosic manmade fibers	**37**		**Transportation Equipment**
	2824	Organic fibers, noncellulosic		3711	Motor vehicles and car bodies
	2841	Soap and other detergents		3713	Truck and bus bodies
	2891	Adhesives and sealants			

There are a limited number of low temperature industrial applications where direct CHP might make sense. **Table 3.8** provides a complete list of the 4-digit SICs included in the technical market screening. Important applications include:

- Food industry - vegetable and fruit drying, cooking
- Plastics - warm air or warm directly or for desiccant regeneration for resin drying
- Textiles - drying
- Wood products - drying kilns
- Paper products - drying
- Chemicals - pharmaceuticals, specialty chemicals, and powders

Direct CHP has also been suggested for boiler preheating that would have application in both commercial and industrial applications, though the contribution to total heat needs in that case is fairly limited making the electric contribution to the site limited unless the site had a very low E/T demand ratio. While the range of applications is limited, the lower net power costs achievable with direct CHP compared to traditional CHP yield a broader range of geographic areas in which the system would be economic. The estimated technical market potential for direct CHP is shown in **Table 3.9.** While representing a good economic application, the technical market potential for direct CHP is only about 12% of the potential for traditional CHP.

Table 3.9. Technical Market Potential for Direct CHP

Market	Units in each Size Bin Average Size				Total Capacity MW
	200 kW	430 kW	860 kW	2,000 kW	
Retrofit	1,876	1,169	710	280	2,042
20-Year New	1,176	781	479	172	1,323

Integrated Energy Systems – Heating, Cooling, Dehumidification, and Power

Many commercial buildings and some industrial processes have thermal use profiles that are very low compared to their electric load profile. For these high E/T demand ratio customers it is either not possible to size a CHP system at all or the economic size would be much lower than could be justified by meeting the base electric load alone. Converting the building air conditioning/dehumidification electric loads to a thermal based load through the use of absorption chillers or desiccant dehumidification systems can have a number of advantages: the most expensive electric load, that used for peak cooling, is eliminated, the remaining electric load has a better load factor, which by itself reduces electric costs. The thermal load of the building is increased making it potentially economic to size a larger CHP system and to contribute to both winter heating and summer cooling. This approach is called an Integrated Energy System (IES) or Building Cooling Heating and Power (BCHP.)

Traditional CHP is limited in many commercial applications by a lack of coincident thermal load. Buildings such as office buildings and retail stores may have seasonal heating loads that are fairly substantial, but only a limited year-round water-heating load. These applications cannot provide adequate thermal utilization for CHP. **Figure 3.3** shows an energy load simulation for a 250,000 square foot office building in Hartford, Connecticut. The top figure shows the monthly thermal loads for the typical building with electric air conditioning. The second figure shows what happens to thermal loads when a portion of the cooling load, that which can be provided by the CHP system, is met by waste-heat absorption chiller. The original building has a peak load of 1,210 kW; a CHP system with 80% thermal utilization would be only 30 kW. By converting a portion of the air conditioning load to an absorption chiller, a 320 kW BCHP system can be installed – in fact, the resulting system size is limited not by a lack of thermal load, but by the building's poor electric load factor. This 320 kW IES/BCHP system reduces the building peak electric load by 55 kW, so the aggregate electric impact is a reduction of 375 kW of electric demand.

The market for absorption systems is most compelling for new buildings. Siting new equipment in confined mechanical rooms of existing buildings can be problematic. Competing with the lower cost of electrically driven equipment already installed is also not as attractive unless equipment replacements are required.

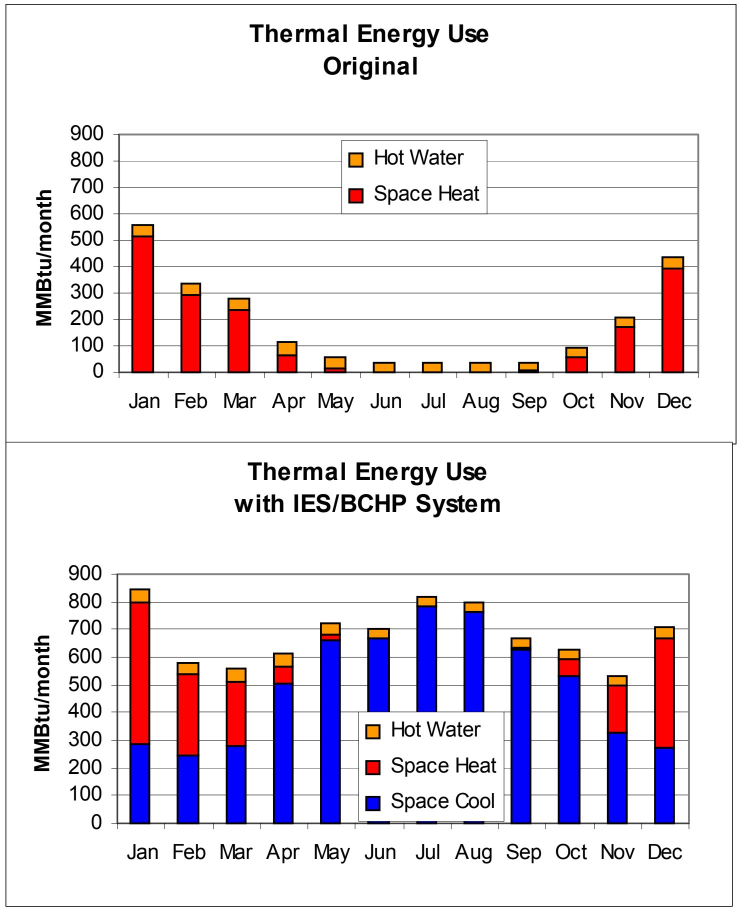


Figure 3.3 Thermal Utilization for Typical IES/BCHP Application (250,000 s.f. office building in Hartford, CT)

Table 3.10 and **Figure 3.4** show the characteristics for the interim development system and the system reflecting the final AMTS goals. In the example, the cooling is provided by a single effect absorption chiller costing $1,500/refrigeration ton (RT) that is driven by 190^{o} F. hot water from the heat recovery boiler. The chiller requires 17,000 Btu/RT (0.7 COP) and displaces 85% of the electric usage from a 9.7 EER rooftop system – for a net effect of 0.85 kW/ton-hr electric savings. The 15% represents electricity used by the absorption system for pumps and cooling tower fans. Thus, in IES-BCHP mode, both the interim and the AMTS Goal system can provide 40 tons of cooling, thereby reducing building electrical demand by 34 kW compared to a building with electric chillers. Because of the higher temperature requirements for the absorber, the total heat recovery is lower than in the simple CHP case. For the calculation of net power costs, it was assumed that over the course of the year the chiller uses 60% of the recovered thermal energy and 40% is used for direct hot water applications. A value of $0.15/kWh was assumed for the displaced electric chiller demand because of the much higher cost of peak-power used for cooling.

Table 3.10. IES/BCHP Installed Cost, Performance, and Net Power Costs

IES/BCHP	Units	Interim		AMTS Goals	
Cost and Performance		Retrofit	New	Retrofit	New
Capacity	kW	200	200	270	270
List Price	$/kW	$650	$650	$500	$500
Heat Recov. and Chiller	$/kW	$651	$511	$501	$389
Installation	$/kW	$325	$325	$293	$293
Capital Cost	$/kW	$1,626	$1,486	$1,293	$1,182
O&M Cost	$/kWh	$0.0160	$0.0160	$0.0110	$0.0110
Heat Rate (HHV)	Btu/kWh	11,154	11,154	9,481	9,481
Electric.Gen. Eff. (LHV)	%	34.0%	34.0%	40.0%	40.0%
Electric.Gen. Eff. (HHV)	%	30.6%	30.6%	36.0%	36.0%
Exhaust Temperature	Degree F	500	500	500	500
Heat Recovered	Btu/kWh	3,438	3,438	2,547	2,547
Tons of Cooling Provided	Ref. tons	40	40	40	40
Net Heat Rate	Btu/kWh	6,856	6,856	6,297	6,297
Overall Efficiency	%	61.4%	61.4%	62.9%	62.9%
Operating Parameters		Same as CHP, except as shown below			
Avoided Cooling Power	kW/ton	0.9945	0.9945	0.9945	0.9945
Peak Power Costs Avoided	$/kWh	$0.15	$0.15	$0.15	$0.15
Net Power Costs	$/kWh	$0.0952	$0.0923	$0.0794	$0.0771

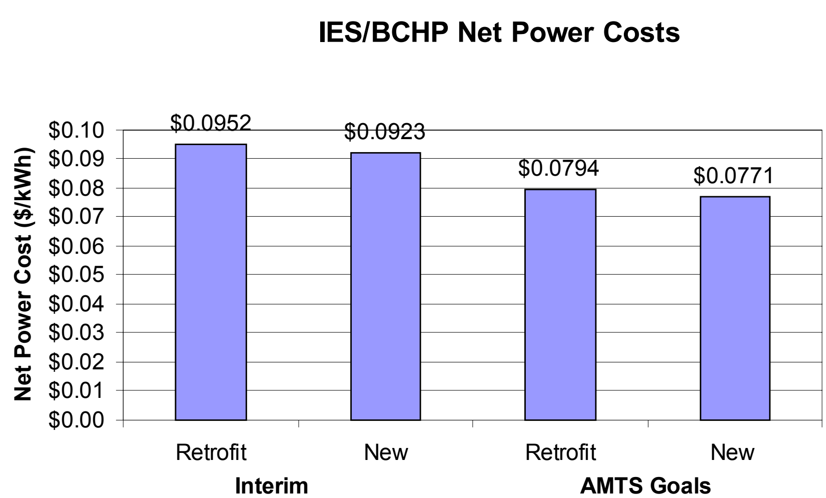


Figure 3.4. IES/BCHP Net Power Costs

Because of the current expense of small absorption systems, it is always more economic to first try to find CHP applications with steady hot water demand. However, the use of thermal output for absorption cooling and/or desiccant dehumidification could increase the size and thereby improve the economics in existing CHP markets such as schools, lodging, nursing homes and hospitals. Use of these advanced technologies in applications such as office buildings, retail stores, restaurants, supermarkets and refrigerated warehouses provides a base thermal load that opens these applications to IES/BCHP.

The applications included in the technical market potential (shown in **Table 3.11**) were all in the commercial and institutional sector – retail establishments, hotels, restaurants, SICs considered to be mostly office applications, meeting places, government buildings, etc. The buildings had to have existing gas utilization, though not at the level required for hot water CHP screening. The results of the screening are summarized in **Table 3.12.**

Table 3.11. SIC Codes for IES-BCHP Value Proposition

SIC	Description	SIC	Description
40	Railroad Transportation	61	Nondepository Credit Institutions
41	Local, Suburban Transit & Interurbn Hgwy Passenger Transport	62	Security & Commodity Brokers, Dealers, Exchanges & Services
42	Motor Freight Transportation	63	Insurance Carriers
43	United States Postal Service	64	Insurance Agents, Brokers and Service
44	Water Transportation	65	Real Estate
45	Transportation by Air	67	Holding and Other Investment Offices
46	Pipelines, Except Natural Gas	70	Hotels, Rooming Houses, Camps, and Other Lodging Places
47	Transportation Services	73	Business Services
48	Communications	75	Automotive Repair, Services and Parking
49	Electric, Gas and Sanitary Services	76	Miscellaneous Repair Services
50	Wholesale Trade - Durable Goods	78	Motion Pictures
51	Wholesale Trade - Nondurable Goods	81	Legal Services
52	Building Matrials, Hrdwr, Garden Supply & Mobile Home Dealrs	86	Membership Organizations
53	General Merchandise Stores	87	Engineering, Accounting, Research, Management & Related Svcs
54	Food Stores	89	Services, Not Elsewhere Classified
55	Automotive Dealers and Gasoline Service Stations	91	Executive, Legislative & General Government, Except Finance
56	Apparel and Accessory Stores	93	Public Finance, Taxation and Monetary Policy
57	Home Furniture, Furnishings and Equipment Stores	94	Administration of Human Resource Programs
58	Eating and Drinking Places	95	Administration of Environmental Quality and Housing Programs
59	Miscellaneous Retail	96	Administration of Economic Programs
60	Depository Institutions	97	National Security and International Affairs

Table 3.12. Technical Market Potential for IES/BCHP

Market	Units in each Size Bin Average Size				Total Capacity
	200 kW	430 kW	860 kW	2,000 kW	MW
Retrofit	25,160	4,580	1,319	267	8,647
20-Year New	27,080	4,331	1,301	233	8,841

3.3 Baseload Power-Only

The simplest DG system utilizing the AMTS would be to provide power only. This section describes baseload power systems that are used to provide power on a more or less continuous basis. No heat recovery system is required and site-engineering requirements are minimized. However, the system must compete with other available power systems. For most commercial and industrial customers with access to the power grid, this competition can be very difficult, making sense in only very high cost areas. For remote power applications, access to the grid may be technically or economically infeasible. Remote power applications represent a very good application for the AMTS, as the only alternatives are other small power generation systems.

Grid Connected or Remote Power

Table 3.13 and **Figure 3.5** show the costs and performance for baseload power only systems for the AMTS systems. Net power costs run about 1.5 to 2 cents/kWh higher than for a new application CHP system with 80% utilization of available thermal energy.

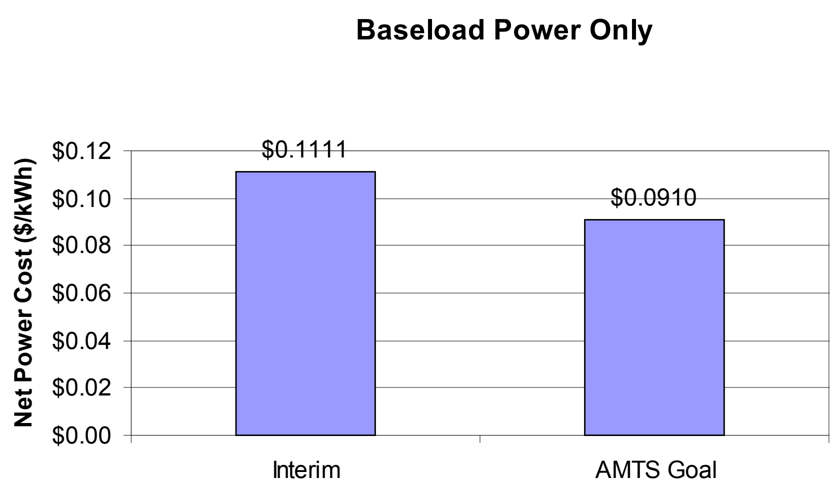


Figure 3.5. Baseload (Power Only) Net Power Costs

Table 3.13. Baseload Power-Only Installed Cost, Performance, and Net Power Costs

System Parameter	Units	Power Only	
Cost and Performance		Interim	AMTS Goals
Capacity	kW	200	270
List Price	$/kW	$650	$500
Heat Recovery	$/kW		
Installation	$/kW	$325	$293
Capital Cost	$/kW	$975	$793
O&M Cost	$/kWh	$0.0160	$0.0110
Heat Rate (HHV)	Btu/kWh	11,154	9,481
Electric.Gen. Eff. (LHV)	%	34.0%	40.0%
Electric.Gen. Eff. (HHV)	%	30.6%	36.0%
Exhaust Temperature	Degree F	500	500
Heat Recovered	Btu/kWh	0	0
Net Heat Rate	Btu/kWh	11,154	9,481
Overall Efficiency	%	30.6%	36.0%
Operating Parameter	Same as CHP, but no thermal recovery		
Net Power Costs	$/kWh	$0.1111	$0.0910

A baseload power-only system can be applied in any commercial or industrial application with some portion of its load available on a year-round basis. The economic potential in grid-connected applications, though, is limited to very high cost areas. For this analysis we screened for all applications in the MarketPlace database with annual power consumption between 1,000-25,000 MWh/year. From this total was subtracted the CHP and IES-BCHP potentials. Therefore, the technical potential for baseload power reflects the applications without CHP and BCHP potential. **Table 3.14** summarizes the technical potential by size.

Table 3.14. Technical Market Potential Baseload Power-Only

Market	Units in each Size Bin – Average Size				Total
	200 kW	430 kW	860 kW	2,000 kW	MW
Retrofit	55,484	21,702	8,207	3,628	34,632
20-Year New	46,185	13,796	4,998	1,868	23,139

Resource Recovery

Resource recovery systems, i.e., systems utilizing a waste or underutilized fuel resource, represent a good market for DG systems in general and the AMTS in particular. By eliminating or greatly reducing fuel costs, resource recovery systems compete very effectively against grid power in most regions of the country. The economics are very similar for applications in the oil and gas industry where the fuel is available on-site and may have limited economic value for collection or sale. Waste fuel and oil and gas applications are also characterized by poor or variable quality fuel. The steady state combustion characteristics of the AMTS are much more flexible in handling special fuel problems than are reciprocating engines. **Table 3.15** and **Figure 3.6** show the economics for the interim and AMTS goals system. An arbitrary value of $1.00/MMBtu was assigned to represent any costs of fuel collection and clean up. The resulting net power costs would be economic throughout the U.S. While efficiency is not as important when the fuel costs are low, the lower installed costs for the AMTS goals system provides for a lower net power cost than for the interim development system.

Table 3.15. Baseload Power-Waste Fuels Installed Cost, Performance, and Net Power Costs

System Parameter	Units	Power Only	
Cost and Performance		Interim	AMTS Goal
Capacity	kW	200	270
List Price	$/kW	$650	$500
Heat Recovery	$/kW	$0	$0
Installation	$/kW	$325	$293
Capital Cost	$/kW	$975	$793
O&M Cost	$/kWh	$0.0160	$0.0110
Heat Rate (HHV)	Btu/kWh	11,154	9,481
Electric.Gen. Eff. (LHV)	%	34.0%	40.0%
Electric.Gen. Eff. (HHV)	%	30.6%	36.0%
Exhaust Temperature	Degree F	500	500
Heat Recovered	Btu/kWh	0	0
Net Heat Rate	Btu/kWh	11,154	9,481
Overall Efficiency	%	30.6%	36.0%
Operating Parameter	Same as Baseload, except for fuel cost		
Fuel Cost $/MMBtu	$/MMBtu	$1.00	$1.00
Net Power Costs	$/kWh	$0.0473	$0.0368

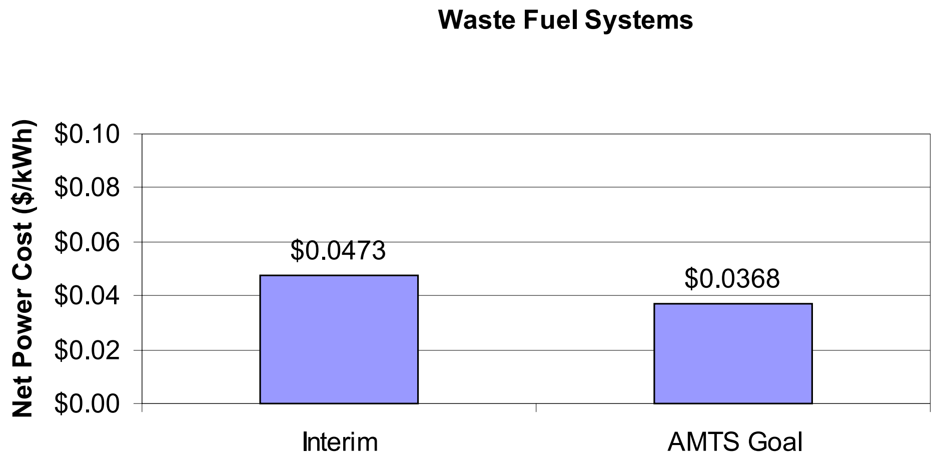


Figure 3.6. Waste Fuels Net Power Costs

Remote Generation at Oil and Gas Wellheads

In the oil and gas market, on-site generation units are utilized to provide remote power while being fueled with unprocessed gas that would ordinarily be flared or simply emitted into the atmosphere. The associated gas from oil wells is in many cases uneconomic to collect into the natural gas pipeline network due to low production quantity and/or poor fuel quality. In most cases, this unproducible gas is flared. Utilizing the fuel to provide power at the well site provides several environmental and economic benefits. Principal environmental benefits are an increase in overall energy efficiency, reduction in emissions of greenhouse gases, and a reduction in the use of grid electricity and its associated, predominantly coal-based, emissions.

The generation of power using what is essentially a no cost fuel provides value over other costly alternatives. On-site power requirements for pumps and other mechanical drive needs range from 60-400 kW per well site. In a baseload application, the AMTS generates electricity at less than 3 cents/kWh. Other alternatives for power include extending electric transmission and distribution lines to the remote locations and the utilization of reciprocating engines fueled by diesel fuel that must be transported and stored on site. These sites are typically served by rural electric cooperatives.

The upstream oil and gas market has been an early niche for the current generation of microturbine products. Activity has been high in western Canada with several distribution agreements announced between microturbine manufacturers and retail providers. An assessment of this application, with the assumption that each well will have its own generator set, indicates that those products (all less than 100 kW in output) are better suited for this application than larger products (>200 kW) likely to be developed in the DOE Advanced Microturbine System Program. This is due primarily to the limited amount of fuel energy from the gas flared available at each well. Statewide average generation capability per well in states with a notable amount of vented or flared gas ranges from approximately from 1 to 250 kW per well. Only Wyoming and South Dakota have average generation capability over 100 kW per well. The distribution is highly concentrated at the lower end with the national average of just over 11 kW per well.

The potential technical market for a 200-270 kW AMTS in this application is shown in **Table 3.16.** The domestic potential is predominantly concentrated in several Western states, with Wyoming being the best suited for the AMTS. The potential for the states with an average well generation capability of greater than 40 kW but less than 250 kW (South Dakota, Utah, Alaska, and Mississippi) was estimated by assuming several wells were in close enough proximity to be easily fuel a 250 kW AMT unit. In those cases, a single AMTS unit would be fueled by gas from two to six wells. A follow-up assessment of the actual proximity of wells to each other within a field and the economic viability of gathering gas from multiple wells to fuel a unit in these and other states may provide more accuracy in determining the actual penetration of the AMT in the oil and as market.

The projected growth for 2001-2010 was conservatively estimated by assuming that the new well trends of the past four years would continue through 2010. New wells were assumed to have the same state-by-state distribution as current inventory of wells.

Table 3.16. Potential Technical Market for Oil and Gas Resource Recovery

Existing US Oil & Gas Resource Recovery						Projected Growth 2001-2010		
State	**Vented or Flared Gas (MMcf)**	**Ave. Well Generation Capacity (kW)**	**Potential AMT Units**	**Capacity (MW)**	**Equipment Sales Revenue ($MM)**	**Potential AMT Units**	**Capacity (MW)**	**Equipment Sales Revenue ($MM)**
Wyoming	144,566,000	253.7	7557	1889.3	944.63	66	16.5	8.25
Utah	13,835,000	67.5	905	226.3	113.13	29	7.3	3.63
Alaska	7,098,000	41.5	377	94.3	47.13	19	4.8	2.38
South Dakota	1,555,000	128.9	160	40.0	20.00	1	0.3	0.13
Mississippi	2,745,000	47.3	153	38.3	19.13	8	2.0	1.00
Remaining US	180,208,000	6.0	-	-	-	-	-	-
TOTAL	350,007,000	11.2	9152	2288.0	1144.0	123	30.8	15.38

Sources: American Gas Association, EIA, Independent Petroleum Association of America, State Oil & Gas Agencies, Onsite Energy Corp., Rig Location & Permit Report Service

Landfill Resource Recovery

The use of DG systems at landfills operating on the collected landfill gas has been growing at about 15% per year. In many areas, these DG systems benefit from rules that require utilities to purchase their power output and other incentives to encourage the use of renewable fuels. While growing rapidly now, this is ultimately a small market overall that will likely reach saturation when the AMT is commercially available. As of mid-1999, there were over 270 landfill gas recovery and utilization projects in the US. The US Environmental Protection Agency (EPA) estimates approximately an additional 500 candidate sites for project development. The EPA estimated distribution by top states of existing and candidate waste to energy sites is presented in **Table 3.17**. Target sites for the AMT are landfill sites with approximately 200,000 – 1.5 million tons waste in place. Based on the projected efficiency of the AMT, this corresponds to 250 kW to 2.5 MW of electricity generation. This technical market potential is shown in **Table 3.18**. The average size plant for this application in the EPA identified candidate sites is in the 2-5 MW range. The average sized AMT power plant identified in this assessment of the market is just under 2 MW.

Table 3.17: EPA Identified Landfill Waste to Energy Opportunity

State	Existing Waste to Energy Projects	Capacity (MW)	EPA Total Candidate Projects	EPA Estimated Capacity from Total Candidate Projects (MW)
Texas	7	66	57	257
California	56	480	43	235
Illinois	36	209.	38	206
Ohio	6	54	29	145
Indiana	10	74	26	102
North Carolina	10	41	36	95
Florida	9	64	17	77
Alabama	3	18	21	74
Colorado	1	23	9	70
Washington	3	16	11	68
Kentucky	1	31	20	65
Missouri	4	25	15	64
Tennessee	2	10	17	61
Remaining US	85	608	177	532
TOTAL	260	1718	516	2051

Source: EPA Landfill Methane Outreach Program

Table 3.18: AMT Landfill Waste to Energy Technical Market Potential

State	AMT Candidate Sites	Potential Units	Ave. Plant Size (kW)	Potential Statewide Capacity (MW)	Potential Statewide Equipment Revenue ($MM)
North Carolina	15	129	2150	32.3	16.1
Texas	10	85	2125	21.3	10.6
Alabama	8	67	2094	16.8	8.4
California	13	67	1288	16.8	8.4
Iowa	5	45	2250	11.3	5.6
Kentucky	5	39	1950	9.8	4.9
Tennessee	5	38	1900	9.5	4.8
Florida	4	36	2250	9.0	4.5
Illinois	5	33	1650	8.3	4.1
Wisconsin	5	32	1600	8.0	4.0
Ohio	4	30	1875	7.5	3.8
Louisiana	3	27	2250	6.8	3.4
Maryland	3	27	2250	6.8	3.4
Virginia	3	27	2250	6.8	3.4
Pennsylvania	4	23	1438	5.8	2.9
Georgia	3	20	1667	5.0	2.5
Indiana	3	20	1667	5.0	2.5
New York	2	20	2500	5.0	2.5
Missouri	3	19	1583	4.8	2.4
Nebraska	2	19	2375	4.8	2.4
Oklahoma	2	19	2375	4.8	2.4
Utah	2	19	2375	4.8	2.4
Connecticut	2	18	2250	4.5	2.3
Nevada	2	18	2250	4.5	2.3
Oregon	2	18	2250	4.5	2.3
Kansas	1	9	2250	2.3	1.1
Massachusetts	1	9	2250	2.3	1.1
Minnesota	1	9	2250	2.3	1.1
Washington	1	9	2250	2.3	1.1
New Jersey	1	8	2000	2.0	1.0
Colorado	0	0	0	0.0	0.0
Total/Avg.	120	939	1956	234.8	117.4

Landfill methane potential is expected to remain constant between 2001 and 2010. This is due to the implementation of the New Source Performance Standards and Guidelines (referred to as the Landfill Rule) under the Clean Air Act (March 1996). The Landfill rule requires large landfills to collect and combust or use landfill gas emissions.

Coalbed Methane

Coalbed Methane may also be used as a fuel for power generation to either power onsite needs of for export to the grid. Electricity demand at mines comes primarily from ventilation systems that must operate continuously and other mining equipment (e.g., mining machines, conveyor belts, and elevators). Ventilation systems comprise up to 60% of the electricity needs at mines. On-site demand ranges from approximately 2–50 MW.

The heating value of coalbed methane can be much lower than natural gas. It can range from 300 (gob gas) to 950 (vertical wells) Btu/scf. **Table 3.19** illustrates the wide range of heating value of Coalbed methane utilization options.

Table 3.19. Heating Values of Coalbed Methane Utilization Options

Recovery Method	Range of Btu Quality (Btu/cf)
Vertical Wells (Pre-mining degasification)	>950
Gob Wells	300-950
In-Mine Bores	Up to 950
Ventilation Air	10-20

Source: EPA

A methane-gas mixture with a heating value of at least 350 Btu/scf is generally suitable for gaseous fuel electricity generation. Vertical wells, gob wells, and in-mine boreholes are acceptable methods of recovering methane for power generation. One potential problem with using gob gas is that production, methane concentration, and rates of flow are generally not predictable. Variations in Btu content of the fuel may cause difficulties. Blending with methane may be needed to ensure variations in the heating value of the fuel remain within an acceptable range.

In its Coalbed Methane Outreach Program, EPA identified 79 potential sites for power generation resource recovery. From that list of candidate mines, those with potential to generate 250-2500 kW were identified as potential sites for the AMTS. **Table 3.20** summarizes the AMT potential technical market of those sites. Consistent with the landfill resource technical potential, the energy conversion was based on the efficiency of the AMTS.

Table 3.20: AMT Coalbed Methane Resource Recovery Potential Technical Market

State	AMT Candidate Sites	Potential Units	Ave. Plant Size (kW)	Potential Statewide Capacity (MW)	Potential Statewide Equipment Revenue ($MM)
Kentucky	7	56	2,000	14.0	7.0
Illinois	6	34	1,417	8.5	4.3
Pennsylvania	3	25	2,083	6.3	3.1
Ohio	3	16	1,333	4.0	2.0
Colorado	2	11	1,375	2.8	1.4
West Virginia	2	9	1,125	2.3	1.1
Utah	1	7	1,750	1.8	0.9
Virginia	1	5	1,250	1.3	0.6
Indiana	1	4	1,000	1.0	0.5
New Mexico	1	3	750	0.8	0.4
Alabama	0	0	0	0.0	0.0
Total/Avg.	27	170	1,574	42.5	21.3

Source: EPA, Onsite Energy

Since the fuel is essentially available at no cost in resource recovery applications, high efficiency is not critical. Fuel quality is an issue as these fuels may have corrosive contaminants, low energy density, and variable characteristics. Management of these fuel characteristics is an important part of an on-site generation system in this application. The fuel flexibility and low maintenance requirements of microturbine systems are an advantage over reciprocating engines in this segment.

Peakshaving and Reliability

Power-only systems can also be applied for a limited number of hours per year to shave the peak power demand. With separate demand and energy charges from most utilities, customers can often save a large part of their energy bill by controlling their peak demand.

For a specific subset of customers that require high reliability service, it may be possible to design a system that provides both economic peakshaving and backup power when needed. This approach is called *peaking with reliability*. For this customer, instead of having both diesel back up generators for standby and the AMTS for peakshaving, the AMTS could serve both functions. The added value of the reliability function is in the avoidance of the cost of the diesel gen-set. **Table 3.21** and **Figure 3.7** show the economic value for these two types of peakshaving applications.

Virtually any customer can implement a peakshaving system from a technical standpoint. The economic value depends on the rate structure under which the customer receives electric service. For example, there are 142,000 commercial customers with peak electric demand between 250 and 1,000 kW. The value in use depends more on the characteristics of the electric rates than the characteristics of the application. For the technical market potential was estimated by screening all of the baseload power-only applications.

Table 3.21. Peakshaving Power-Only Installed Cost, Performance, and Net Power Costs

System Parameter	Units	Peakshaving		Peaking & Reliability	
Cost and Performance		Interim	AMTS Goal	Interim	AMTS Goal
Capacity	kW	200	270	200	270
List Price	$/kW	$650	$500	$650	$500
Installation	$/kW	$325	$293	$325	$293
Capital Cost	$/kW	$975	$793	$825	$959
Avoided Diesel GenSet				-$410	-$410
O&M Cost	$/kWh	$0.016	$0.011	$0.016	$0.011
Heat Rate (HHV)	Btu/kWh	11,154	9,481	11,154	9,481
Electric.Gen. Eff. (LHV)	%	34.0%	40.0%	34.0%	40.0%
Electric.Gen. Eff. (HHV)	%	30.6%	36.0%	30.6%	36.0%
Operating Parameter					
Annual Capacity Factor	%	23%	23%	23%	23%
Cost of Capital	%	10%	10%	10%	10%
Fuel Cost $/MMBtu	$/MMBtu	$6.50	$6.50	$6.50	$6.50
Net Power Costs	$/kWh	$0.1678	$0.1371	$0.1223	$0.1173

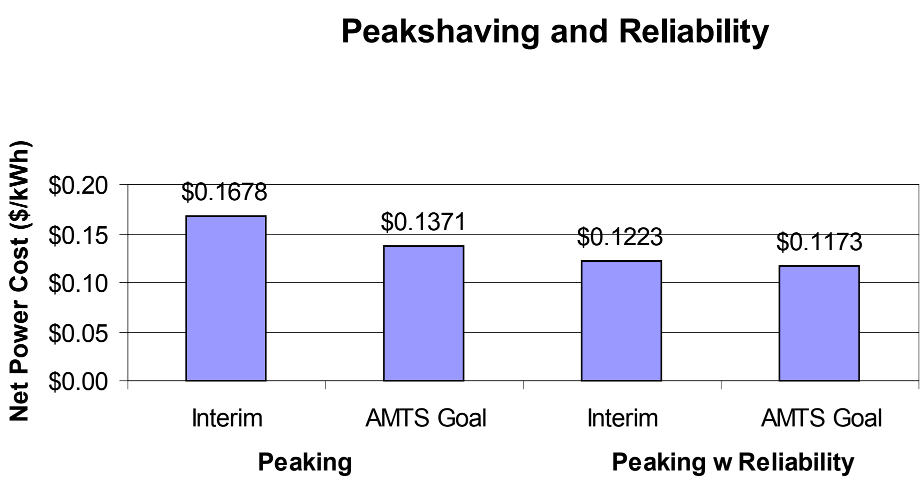


Figure 3.7. Peakshaving and Reliability Net Power Costs

Table 3.22. SIC Codes for Peaking/Reliability Value Proposition

Industrial			
20	**Food and Kindred**	**30**	**Rubber and Miscellaneous Plastic Products**
2023	Dry, condensed and evaporated dairy products	**29**	**Petroleum Refining**
2024	Ice cream and frozen deserts	2911	Petroleum refining
2082	Malt beverages	2951	Asphalt paving mixtures and blocks
2083	Malt	2952	Asphalt felts and coatings
2086	Bottled and canned soft drinks	**32**	**Stone, Clay, Glass and Concrete**
2097	Manufactured ice	3211	Flat glass
26	**Paper and Allied Products**	3221	Glass containers
2621	Paper mills	3229	Pressed and blown glass, nec
2631	Paperboard mills	**36**	**Electronic Equipment**
2653	Corrugated and solid fiber boxes	3672	Printed circuit boards
27	**Printing**	3674	Semiconductors and related devices
2711	Newspapers	3675	Electronic capacitors
28	**Chemicals**	3676	Electronic resistors
2821	Plastics materials and resins	3677	Electronic coils and transformers
2822	Synthetic rubber	3678	Electronic connectors
2823	Cellulosic manmade fibers	3679	Electronic components, nec
2824	Organic fibers, noncellulosic		
2834	Pharmaceutical preparations		
2836	Biological products, except diagnostic		
Commercial			
40	**Railroad Transportation**	**62**	**Security & Commodity Brokers, Dealers, Exchanges & Services**
4013	Switching and terminal services	**80**	**Health Services**
43	**US Postal Service**	8051	Skilled nursing care facilities
45	**Air Transport**	8052	Intermediate care facilities
4512	Air transportation, scheduled	8062	General medical and surgical hospitals
4513	Air courier services	8063	Psychiatric hospitals
48	**Communications**	8092	Kidney dialysis centers
49	**Electric Gas and Stationary Services**	**92**	**Justice, Public Order and Safety**
4922	Natural gas transmission	9211	Courts
4924	Natural gas distribution	9221	Police protection
4941	Water supply	9223	Correctional institutions
4952	Sewerage systems	9224	Fire protection
60	**Depository Institutions**	9229	Public order and safety, nec
61	**Nondepository Credit Institutions**	**97**	**National Security and International Affairs**
		9711	National security

Table 3.22 shows the business activities included in the technical market potential screen. Reliability value is important to customers with continuous manufacturing processes that would be disrupted by an outage such as food, paper, printing, chemicals, refining, plastic, glass, and electronic equipment. Communications and financial institutions are another high reliability customer – though in some cases, the need for reliability is so great as to preclude interest in a dual-purpose system that includes economic peakshaving. Health and safety represents a third application including, utilities, hospitals, public buildings, prisons, and national security.

Table 3.23 shows the technical market potential for peaking with reliability value added. The technical market potential for peaking alone was assumed to the same as shown for baseload power continuous power.

Table 3.23. Technical Market Potential for Peaking with Reliability

	Units in each Size Bin Average Size				Total
Market	200 kW	430 kW	860 kW	2,000 kW	MW
Retrofit	19,568	7,065	3,766	1,063	12,279
20-Year New	13,559	4,637	2,330	575	7,836

3.4 Technical Market Potential Summary

The state-by-state technical market potentials for each value proposition are shown in **Table 3.22**. These values are used in the state-by-state economic screening described in the next section. As previously stated, the technical market potential reflects the associated capacity for the installations that are technically feasible within the operating requirements of each value proposition. Directly comparing one value proposition to another is not particularly meaningful as each value proposition varies in terms of its economic benefit to the user.

Table 3.22 State-by-State Technical Market Potential Estimates

	Baseload Power Only		CHP (Hot Water)		IES-BCHP		Direct CHP		Peaking with Reliability		Oil & Waste
	Retrofit	20-Year New	Retrofit	20-Year New	Retrofit	20-Year New	Retrofit	20-Year New	Retrofit	20-Year New	Total
State	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW
Alabama	395	203	324	197	90	99	50	29	151	94	17
Alaska											104
Arizona	189	95	187	134	178	171	12	8	99	64	
Arkansas	157	87	198	114	65	51	24	17	78	51	
California	3,453	2,590	1,650	1,120	1,044	1,255	156	111	1,113	743	17
Colorado	846	698	55	35	53	64	4	2	155	88	3
Connecticut	482	334	281	191	150	135	27	19	188	130	5
Delaware	105	67	71	32	30	26	14	7	54	25	
Florida	1,603	1,006	514	380	394	407	33	22	474	279	9
Georgia	811	479	535	324	232	261	60	35	343	196	5
Hawaii											
Idaho	230	157	17	7	11	10	0		53	33	
Illinois	1,164	761	1,106	735	560	572	163	117	592	393	17
Indiana	642	389	745	459	225	204	134	83	373	268	6
Iowa	240	133	277	184	133	101	39	27	134	91	11
Kansas	127	56	170	107	90	71	17	14	81	49	2
Kentucky	419	220	378	209	122	110	47	32	202	129	24
Louisiana	261	150	230	124	122	109	23	11	142	70	7
Maine	312	186	9	4	6	7	1		83	48	
Maryland	532	357	245	160	213	222	23	17	178	102	7
Massachusetts	1,043	670	579	359	299	388	50	35	409	276	2
Michigan	2,655	1,948	244	136	97	97	66	24	642	472	
Minnesota	1,051	792	146	96	72	89	24	14	245	171	2
Mississippi	216	163	197	120	62	52	15	12	93	55	42
Missouri	379	235	420	263	200	172	68	43	212	129	5
Montana	169	104	8	3	7	3			33	19	
Nebraska	122	76	135	91	76	63	17	12	65	42	5
Nevada	118	122	110	87	186	183	6	4	44	27	5
New Hampshire	339	241	17	11	8	9	0		80	59	
New Jersey	1,111	659	532	318	363	369	71	58	475	286	2
New Mexico	118	72	65	42	66	47	1	1	49	27	1
New York	3,147	2,196	877	512	552	587	54	35	936	607	5
North Carolina	1,035	564	556	307	195	190	67	42	392	235	32
North Dakota	112	80	11	12	9	7	0		27	18	
Ohio	1,548	1,029	1,273	830	436	439	188	129	764	534	12
Oklahoma	116	75	181	118	103	80	25	16	76	48	5
Oregon	825	600	200	131	128	131	11	8	181	119	5
Pennsylvania	2,013	1,242	1,178	725	463	471	174	101	787	488	12
Rhode Island	140	93	95	55	36	30	11	8	67	45	
South Carolina	397	206	282	149	77	71	41	29	161	100	
South Dakota	122	73	12	6	7	9	1		30	18	41
Tennessee	608	343	544	324	203	199	55	27	269	164	10
Texas	836	498	919	561	523	506	126	81	480	272	21
Utah	245	158	88	49	54	36	9	5	65	32	248
Vermont	175	101	3	2	2	1			49	27	
Virginia	948	672	453	292	369	388	52	35	336	196	8
Washington	1,378	1,029	288	165	215	233	26	15	322	204	2
West Virginia	226	127	107	68	49	35	10	8	88	53	2
Wisconsin	1,383	948	253	166	68	74	46	28	387	250	8
Wyoming	92	59	6	3	7	5	0	0	19	11	1,922
Grand Total	34,632	23,139	16,768	10,516	8,647	8,841	2,042	1,323	12,279	7,836	2,628

SECTION 4 – ECONOMIC AND MARKET ANALYSIS

This section presents a state-by-state screening of economic competitiveness and economic market potential by application (value proposition.) The value proposition for the AMTS was compared to prevailing natural gas and power prices in the U.S. on a state-by-state basis. These comparisons determined if the particular technology configuration was economic in a given application in each state. The comparative economic advantage was used to estimate the economic market potential. The economic market potential is defined in terms of the percentage of customers identified as the technical market potential for which a particular application was economically beneficial. The resulting product of this economic acceptance share and the technical potential by state was aggregated to arrive at economic market potentials for the U.S. for each of the applications described in the previous sections. This screening method does not take into account future changes in gas and electric prices[9] or the effects of rate structures on the project economics. The screening is intended to show on a regional basis where the underlying economics are favorable for the AMTS

4.1 Regional Power and Fuel Prices

A first-order measure of economic potential for distributed generation is the relationship between retail electric prices and retail natural gas prices. This relationship, figured in various ways, is often called the *spark spread.* Customers in states with a large spark spread will be able to earn an economic surplus by generating electricity with a natural gas-fired onsite generator. This section defines the state-by-state electric and power prices and defines the spark spread by state.

Figure 4.1 shows the geographical distribution of commercial power prices in the U.S. The high price regions are in the Northeast including New England and in California. With some exceptions, moderately high prices also exist in the Southwest and in the industrialized Midwest. These are the states that represent the target market for the AMTS.

Figure 4.2 shows these data in a different way. The state-by-state average commercial electric prices are ordered from highest to lowest. The commercial sector electric consumption for each state is converted to a percentage of the total U.S. commercial consumption. The resulting graph represents a cumulative distribution curve. For a given power price, the graph shows the percent of customers that pay that price or higher. This curve is useful for determining the percent of the market that pay power prices above the cost of a DG alternative. The mean commercial power price in the U.S. is 6.86 cents/kWh. The median price is 6.57 cents/kWh.

The geographical distribution of average commercial and industrial retail natural gas prices is shown in **Figure 4.3**. Gas prices are lowest in the producing regions of the country: the Southwest and the Mountain states and also low in states adjacent to Canadian import points. **Figure 4.4** shows the percentile curve. The average gas price is $6.50/MMBtu; the median is $6.39/MMBtu. These averages (July 2000 to June 2001) have already shown signs of coming down in some parts of the country. The state-by-state pricing is shown in **Table 4.1**

---

[9] *EIA Annual Energy Outlook 2003* baseline forecast shows a fairly stable electric to gas price ratio in the commercial sector with a national average that varies between 3.4 and 3.0 over the forecast period (2003-2025.)

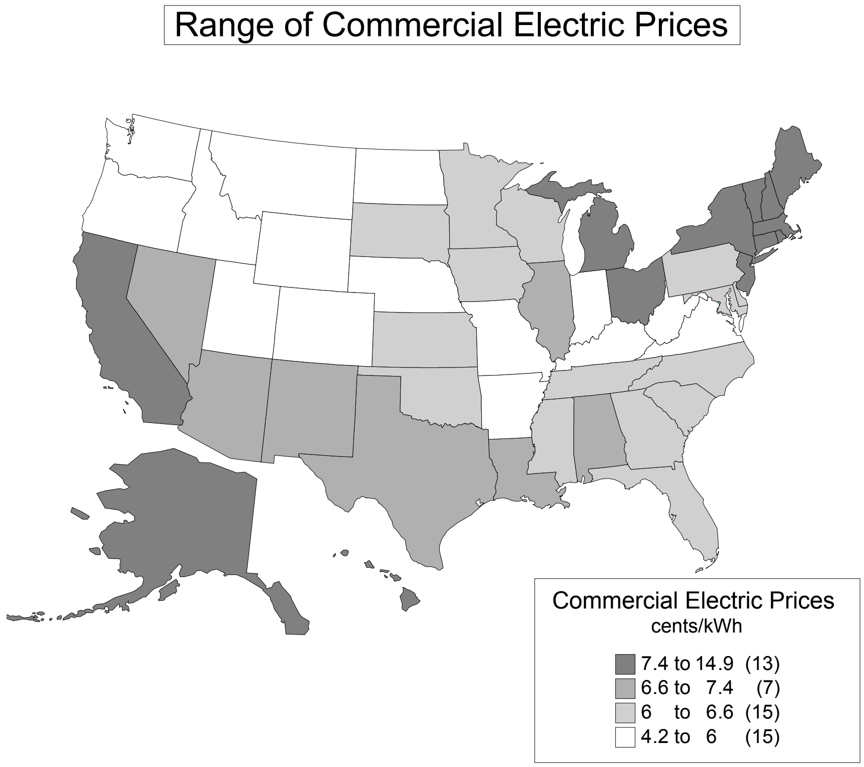


Figure 4.1. Distribution of Power Prices in the U.S. (2000-2001)

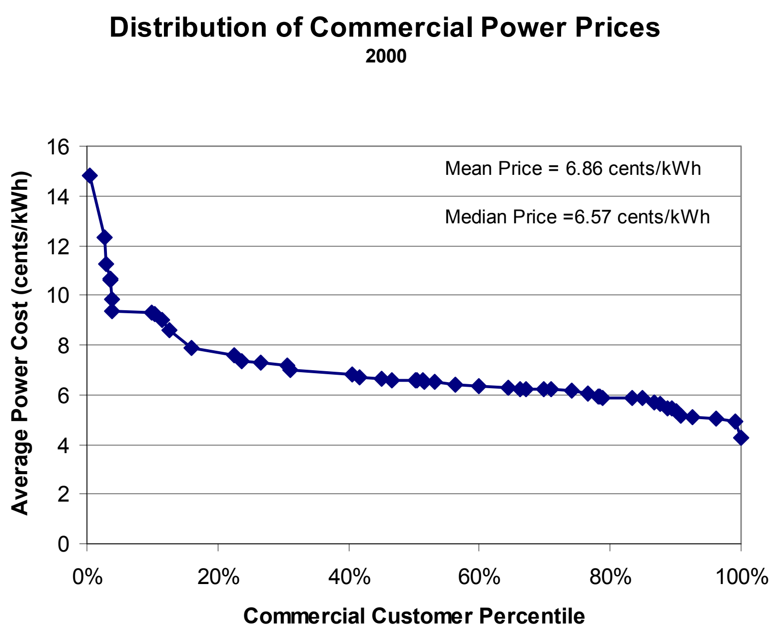


Figure 4.2. Power Costs by Percentile of the Market (2000-2001

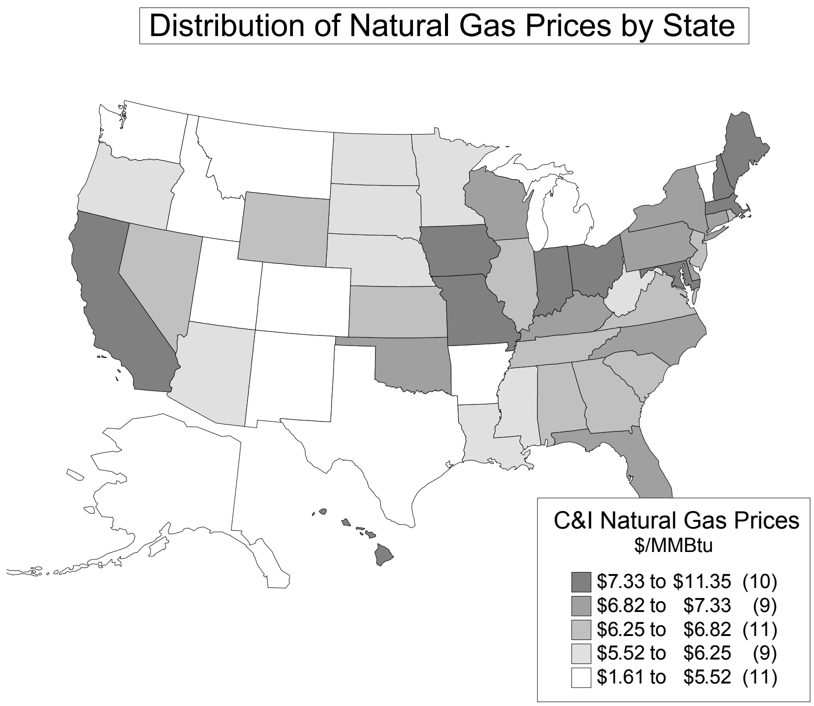


Figure 4.3. Distribution of Natural Gas Prices in the U.S. (2000-2001)

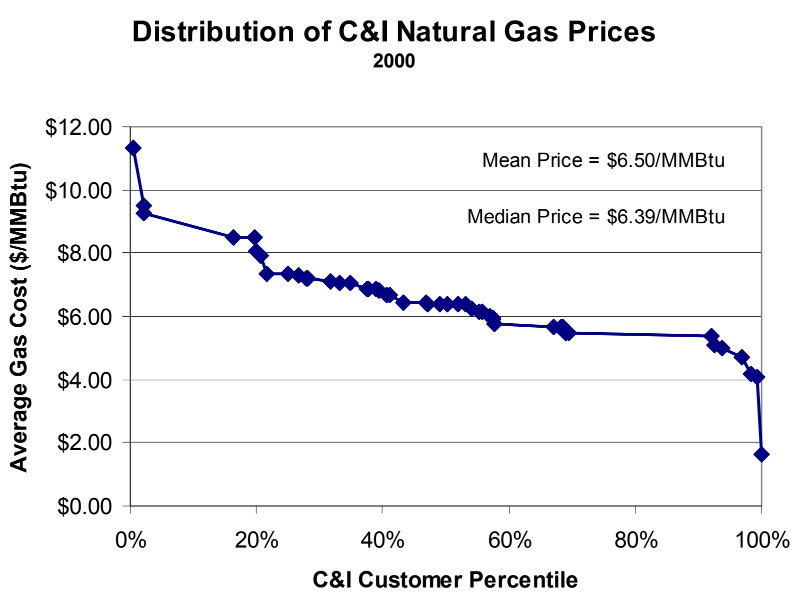


Figure 4.4. Natural Gas Prices by Percentile of the Market (2000-2001)

Table 4.1 State-by-State Summary of Average 2000-2001 Gas and Electric Prices

State	Electric cents/kWh	Gas Price $/MMBtu	State	Electric cents/kWh	Gas Price $/MMBtu
Alabama	6.65	$6.40	Montana	5.89	$5.45
Alaska	9.34	$1.62	Nebraska	5.43	$5.97
Arizona	7.35	$5.65	Nevada	6.72	$6.66
Arkansas	5.95	$4.18	New Hampshire	11.28	$9.24
California	9.30	$8.50	New Jersey	8.59	$6.45
Colorado	5.64	$4.10	New Mexico	6.97	$5.47
Connecticut	9.27	$7.18	New York	12.30	$7.11
Delaware	6.55	$6.85	North Carolina	6.40	$7.19
Florida	6.25	$7.07	North Dakota	5.94	$5.75
Georgia	6.56	$6.37	Ohio	7.57	$8.47
Hawaii	14.83	$11.33	Oklahoma	6.20	$7.30
Idaho	4.26	$5.52	Oregon	5.11	$5.66
Illinois	7.15	$6.43	Pennsylvania	6.29	$6.86
Indiana	5.88	$7.33	Rhode Island	9.83	$6.82
Iowa	6.59	$7.33	South Carolina	6.16	$6.39
Kansas	6.24	$6.25	South Dakota	6.54	$5.90
Kentucky	5.05	$6.85	Tennessee	6.32	$6.66
Louisiana	7.31	$5.66	Texas	6.83	$5.39
Maine	10.69	$8.07	Utah	5.17	$5.10
Maryland	6.55	$11.34	Vermont	10.60	$5.46
Massachusetts	9.03	$9.51	Virginia	5.66	$6.37
Michigan	7.90	$4.71	Washington	4.93	$4.97
Minnesota	6.22	$5.99	West Virginia	5.47	$6.14
Mississippi	6.51	$6.15	Wisconsin	6.02	$7.04
Missouri	5.85	$7.90	Wyoming	5.33	$6.41

Source: EIA

4.2 AMTS Economic Market Screen

Based on the cost and performance of the various AMTS configurations in each application, the net power cost is calculated for each state based on the prevailing natural gas and electric prices from Table 4.1 above. For each state, the economic market potential is based on the payback period (capital cost/net annual savings) for the application in that state.

For each state, an economic acceptance share (as a percent of the technical market potential) is calculated based on the payback. For paybacks of 2 years or less, the economic acceptance share equals 100% -- that is it is assumed that all sites within the technical potential would ultimately adopt the AMTS solution for that application in that state. For paybacks of 8 years or more, the economic acceptance share equals zero – there would be no market penetration of AMTS for that application in that state. The economic acceptance share varies between these 0 and 100% points in a linear fashion as shown in **Figure 4.5**. For a 6-year payback that corresponds to a zero, or neutral, net present value at the 10% discount rate the calculated economic acceptance share is 33%. The economic acceptance shares are calculated for each state and are used to determine what percentage of the technical potential in each state that is included in the economic market potential. The state-by-state technical potentials for each application are summarized in Appendix C. All of the baseload power-only and CHP applications were analyzed in this way.

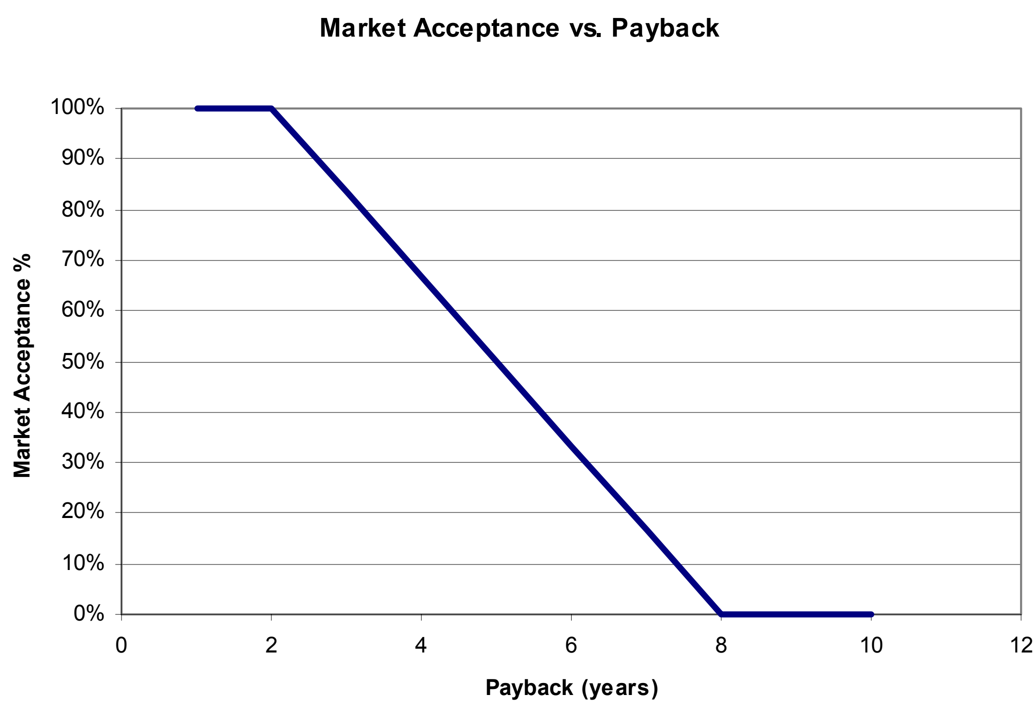


Figure 4.5 Market Acceptance Share Assumptions in the Market Screening Model

The peaking and peaking with reliability analyses were based on a specific rate analysis of 15 of the largest utilities in the U.S. The economic potential was determined by the comparison of the net power costs of an AMTS operating 2,000 hours/year with the estimated peak-load power costs for that utility. The market shares were estimated using the total technical potentials for the states included by the 15 utility companies. These states reflect 60% coverage of the total U.S.

The screening methodology can be shown using the AMTS goals system in a CHP retrofit application as an example. Referring back to the system and application assumptions presented in Table 3.3, the AMTS with hot water heat recovery in a retrofit application costs $1,071/kW and is capable of providing a combined electric and thermal efficiency of 68.7%. It was assumed that 80% of the available thermal energy is used on-site. **Table 4.2** shows the payback calculation for the state of California using the prevailing power and gas costs of $0.093/kWh and $8.50/MMBtu respectively. The 270 kW AMTS system produces 1.89 million kWh per year and consumes almost 18,000 MMBtu/year of natural gas – though the CHP saves about 4,700 MMBtu/year in avoided boiler fuel. California represents a good economic market in the U.S. with an average payback of 5.49 years. While a payback of over 5 years is considered by many developers to produce little customer motivation for implementation, it should be remembered that this figure represents an average for the state and that there will be applications with paybacks above and below this figure. Therefore, this payback period corresponds to an economic acceptance share of 42%. Based on the AMTS technical potential in New York for traditional CHP of 1,650 MW, the economic market potential is equal to 689 MW.

In a similar fashion, the paybacks for each state are calculated using the prevailing electric and gas rates. The paybacks by state are ordered from lowest to highest in **Figure 4.6** to show the range of paybacks in the total U.S. market. The graph does not show paybacks above 10 or those that are negative. Based on this analysis about 16% of the technical potential for the retrofit market is economic – a figure that corresponds to 2,700 MW. **Figure 4.7** shows the geographic distribution of the economic acceptance shares. The CHP market is best in the Northeast, California and the Southwest with Michigan also showing some potential.

Table 4.2. Payback for AMTS CHP Retrofit for California

AMTS Goal	Annual Consumption	Unit Cost	Annual Costs
Fuel Cost	17,939 MMBtu/year	$8.50	($152,425)
O&M	1.89 Million kWh/year	$0.011	($20,814)
Avoided Power Costs	1.89 Million kWh/year	$0.093	$175,971
Avoided Fuel Costs	4,696 MMBtu/year	$8.50	$49,877
		Annual Savings	$52,609
		Capital Cost	$289,060
		Payback	5.49
		Technical Potential MW	1,650
		Economic Acceptance	42%
		Economic Potential MW	689

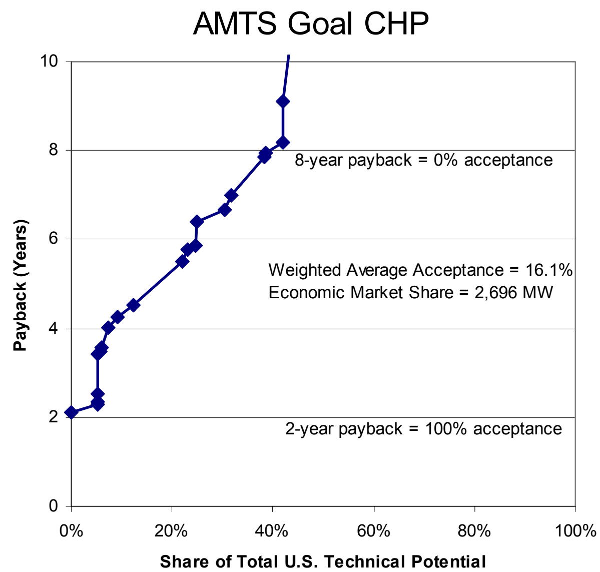


Figure 4.6. Paybacks for AMTS CHP Retrofit by Share of Total Technical Potential

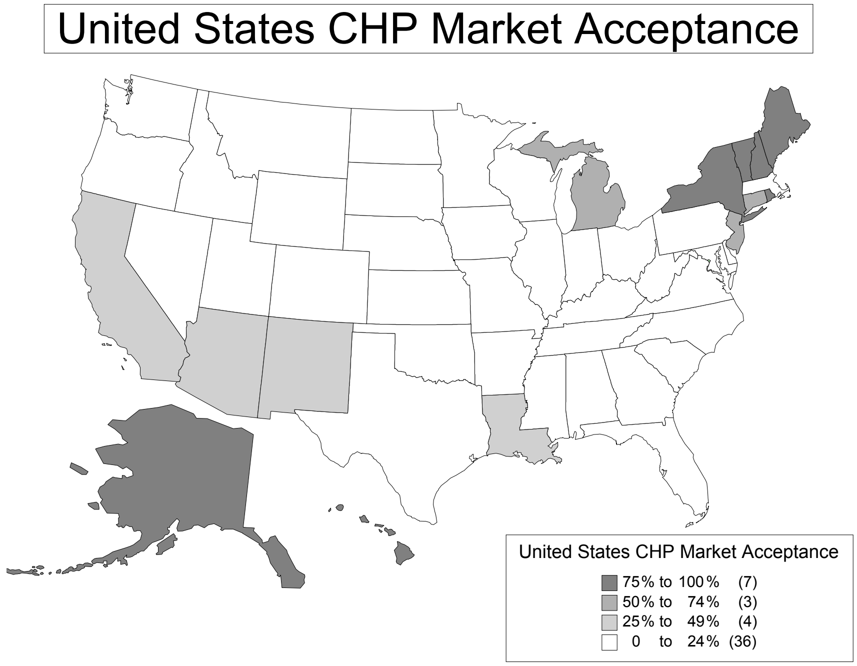


Figure 4.7 Geographic Distribution of Economic Acceptance Shares for AMTS-HE CHP Retrofit

A different screening methodology was developed to evaluate peakshaving economic acceptance levels because average rates do not adequately reflect the features of individual rate structures that determine the differences among peak, average, and off-peak rates. For the peak shaving comparison, 14 utility large customer rate structures were selected for evaluation. These rates reflect a cross section of rates in the U.S. with every geographic region in the continental U.S. covered. The states, from which the 14 utilities were selected, serve 60% of the customers in the U.S.

Actual hourly data for a representative customer was used to calculate on peak, average, and off-peak rates based on the particular tariff selected. The peakshaving and peakshaving with reliability value proposition power costs were compared to these 14 utility peak rates.

The economic acceptance factor was based on a comparison of the net power cost from the AMTS and the average peak rate for each utility. If the AMTS cost is 85% or less than the peak utility rate, then the market acceptance factor is 75%. If the AMTS cost is equal to the peak power rate, the market acceptance factor equals 25%. The acceptance factors were estimated as a linear approximation between these two values. The results of the screen are shown in **Table 4.3.** If the final column is checked, the average running cost of the AMTS is less than the off-peak power cost for the utility. This would indicate that a continuous baseload strategy would be more effective.

Table 4.3. Peaking and Reliability Economic Screen

Utility and Geographic Data					Representative Customer Power Costs			Economic Peak Shavin		eak Shaving with Reliabi		Off Peak
Utility Territory	State	Peaking	Peak/Rel	Region	On-Peak Electric Cost ($/kWh)	Off-Peak Electric Cost ($/kWh)	Average Electric Cost ($/kWh)	Interim Target $/kWh	AMTS Goal Target $/kWh	Interim Target $/kWh	AMTS Goal Target $/kWh	Running Cost $/kWh
								$0.1678	$0.1371	$0.1223	$0.1173	$0.0726
Detroit, MI[1]	MI	4,603	1,115	MW	$0.1565	$0.0640	$0.0902	**1%**	**66%**	**80%**	**80%**	
Chicago, IL[2]	IL	1,925	985	MW	$0.1173	$0.0234	$0.0689			**11%**	**25%**	
Cleveland-Lorain-Elyria, OH[3]	OH	2,577	1,299	MW	$0.0988	$0.0460	$0.0669					
New York, NY[4]	NY	5,343	1,543	NE	$0.1243	$0.0807	$0.1022			**30%**	**44%**	✓
Boston, MA-NH[5]	MA	1,713	685	NE	$0.1185	$0.0906	$0.1001			**14%**	**28%**	✓
Boston, MA-NH[5]	NH	579	139	NE	$0.1185	$0.0906	$0.1001			**14%**	**28%**	✓
Newark, NJ[6]	NJ	1,770	762	NE	$0.1227	$0.0737	$0.1000			**26%**	**40%**	✓
Philadelphia, PA-NJ[7]	PA	3,254	1,275	NE	$0.1132	$0.0701	$0.0915				**13%**	
Hartford, CT[8]	CT	816	318	NE	$0.0922	$0.0485	$0.0712					
Atlanta, GA[9]	GA	1,290	539	SE	$0.1386	$0.0225	$0.0643		**29%**	**64%**	**76%**	
Orlando, FL[10]	FL	2,608	753	SE	$0.0705	$0.0112	$0.0285					
Phoenix-Mesa, AZ[11]	AZ	283	163	SW	$0.1151	$0.0546	$0.0754			**4%**	**19%**	
Fort Worth-Arlington, TX[12]	TX	1,333	752	SW	$0.0680	$0.0366	$0.0423					
San Francisco, CA[13]	CA	6,043	1,857	W	$0.2322	$0.0621	$0.0865	**80%**	**80%**	**80%**	**80%**	
Total MW		34,137	12,185					**4,874**	**8,254**	**3,626**	**4,447**	
% of Technical Market Potential		59.1%	60.6%					**6.33%**	**10.73%**	**61.67%**	**75.64%**	`

(1) Detroit Edison General Service Rate - Schedule D4 -- On-Peak hours are from 11 am to 7 pm
(2) Commonwealth Edison Rate 6 - General Service -- On Peak Hours are from 9 am to 10 pm
(3) Cleveland Electric Illuminating General Service -- On Peak Hours are from 8 am to 10 pm
(4) Consolidated Edison Tate TOU-Schedule 4- Rate III
(5) Boston Edison General Service Rate G-1 -- On-Peak: Jun - Sep -- Off-Peak: Oct - May
(6) Publice Service Electric and Gas
(7) PECO Energy General Service Rate
(8) Connecticut Light and Power Rate 55 -- On-Peak from 7 am to 11 pm
(9) Georgia Power Rate Schedule TOU-GSD-1 -- On Peak Hours are from 12 noon to 9 pm
(10) Florida Power & Light General Service Rate GSLDT-1
(11) Arizona Public Service - Medium General Service
(12) Texas Utilities Electric Company General Service Rate
(13) Pacific Gas and Electric Schedule E-19S

4.3 Summary of Economic Market Potential

Table 4.4 summarizes the technical market potential and the economic market potential for each of the application/technology combinations considered.

Table 4.4. Summary of Economic Market Potential

Value Proposition	Technical Market Potential (MW)	Economic Market Potential			
		Interim Development		AMTS Goals	
		MW	Share	MW	Share
CHP New	10,520	640	6%	2,100	20%
CHP Retrofit	16,770	890	5%	2,700	16%
Direct CHP	3,370	440	13%	1,080	32%
IES-BCHP New	8,840	450	5%	1,270	14%
IES-BCHP Retrofit	8,650	380	4%	940	11%
Base (Retrofit plus New)	57,770	2,810	5%	7,840	14%
Waste Fuels/Oil Industry	2,630	2,630	100%	2,630	100%
Peaking	57,770	4,870	8%	8,250	14%
Peaking w Reliability	20,120	3,630	18%	4,450	22%

The results for each application can be summarized as follows:

- Except for waste fuel applications, the AMTS goals system provides 2-3 times the economic market of the interim development goals system. This result underscores how critical it is for the AMTS to meet cost and performance design goals in order to move into a more broadly competitive position. (The remaining conclusions focus on the AMTS development goals system – final two columns of Table 4.4.)
- Traditional CHP is economic in 16% of the retrofit market and 20% of the new market representing 4,800 MW of potential AMTS sales.
- Direct CHP is more broadly applicable geographically than traditional CHP due to the lower costs and higher efficiency but has a lower capacity potential because the number of applications that can use direct exhaust is much more limited.
- IES-BCHP has a more narrow geographic target market than traditional CHP, though applications within those regions are greater than for traditional CHP, so the economic market is 2,210 MW.
- Baseload power only is limited in terms of geographic target markets when compared to grid power. However, the very large number of facilities in the technical market potential suggest a market of 7,840 MW.
- Waste fuels and oil industry applications are applicable in all geographic regions where technical potential exists due to the very low fuel costs

- Peaking applications are also limited geographically, but offer a very large number of applications in the technical potential so that the economic market potential equals 8,250 MW.
- Adding the reliability value to peaking broadens the geographic reach of the economic markets considerably. However, a smaller share of customers within each region has a technical need for both peakshaving and reliability.
- For applications that do not require matching to a thermal load in addition to the electric load, (baseload, peaking, peaking with reliability) there is a larger technical potential based simply on the larger number of such facilities. Discussions with both the equipment developers and with market developers have raised issues about the realism of penetrating these markets at such high levels.

4.4 Sensitivity Analysis

The AMTS will compete on the basis of the services that it provides. This competition will depend on both the AMTS cost and performance profile and on the prevailing energy prices. There is uncertainty in both of these areas. This section identifies the sensitivity of the net power cost from the AMTS to changes in its performance profile and to changes in input fuel prices. In addition, using the market-screening model described in the previous sections, the sensitivity of the market response is also measured.

Two configurations for the AMTS were used in this analysis. The first represents a system that achieves partial success in meeting the AMTS cost and performance goals, and the second is the AMTS goal system. These systems differ in electric generation efficiency, capital cost, and (non-fuel) operating and maintenance (O&M) costs. **Table 4.5** shows the improvement that is achieved in going from the *Partial Success* to the *AMTS Goals* system. The share that improvements to capital cost, O&M, and efficiency for the CHP and power only applications are shown in **Figures 4.8 and 4.9**.

Table 4.5 Improvement in Net Power Cost for AMTS Systems in CHP and Power Only Application

	Application	
	CHP	Power Only
Net Power Cost	$/kWh	
Interim Development	$0.0888	$0.1111
AMTS Goal	$0.0747	$0.0910
Improvement Shares	$/kWh	
O&M	$0.0050	$0.0050
Capital Cost	$0.0052	$0.0042
Efficiency	$0.0038	$0.0109
Total Improvement	$0.0141	$0.0201

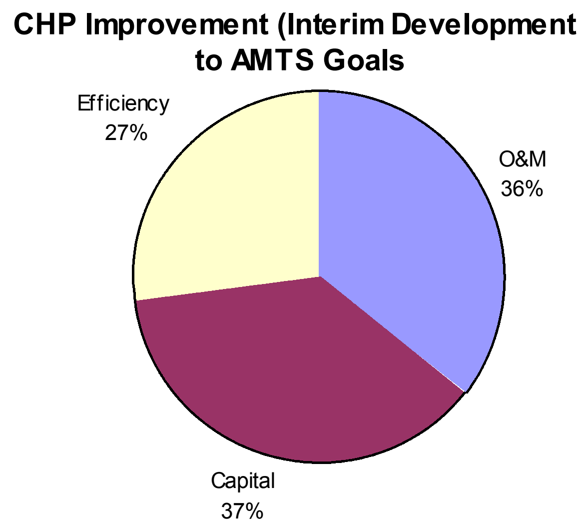


Figure 4.8 Performance Factors Share in Total Improvement in Net Power Cost (CHP)

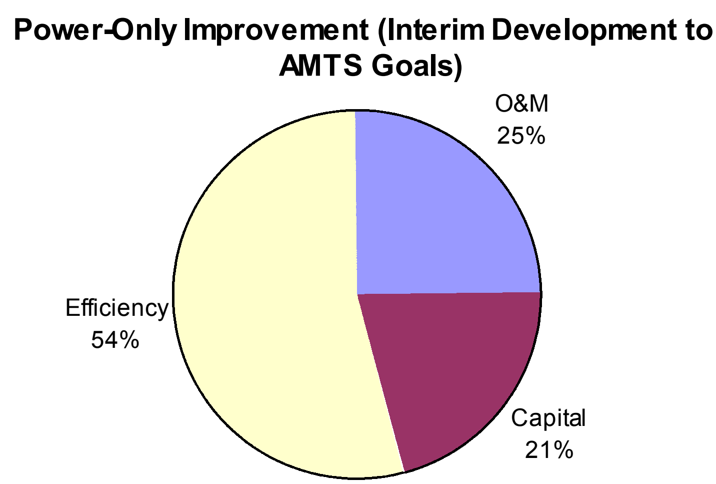


Figure 4.9 Performance Factors Share in Total Improvement in Net Power Cost (Power-Only)

Reductions in O&M and installed capital costs are of nearly equal importance in both CHP and power-only applications. Improving the electrical generating efficiency from 34% to 40% (LHV) provides a much higher share of the total reduction in net power costs for the power-only application (54%) than it does for CHP (27%.) In the CHP application, electrical efficiency is less important because the overall efficiency, that is the sum of the electrical energy and thermal energy, remains relatively constant.

The market impacts produced by changes in the AMTS performance factors can be estimated using the market screening model described in the previous section and varying the AMTS performance factors. Traditional CHP (new) and power-only were chosen to compare the market impacts of changes in AMTS performance factors both with and without heat recovery. **Figure 4.10** compares the market acceptance share as the installed capital cost varies. By definition, there is no change in technical potential, as this value was determined based on the physical fit with each application, not on the economic performance of the system. Therefore, the vertical axis represents the share of the technical potential that is economic. The vertical line represents the base value of installed cost for the CHP system. The graph indicates that there is a niche market for high cost systems. Cost reduction to the AMTS goals will produce a large increase in market acceptance. For every 1% decrease in installed cost there will be a 2% or more increase in market acceptance. The fact that the market is so responsive (elastic) can be explained by reviewing Figure 4.1. There is a tale of about 20% of electricity customers in the U.S. that pay much higher rates. Below this point, the price curve is fairly flat. The AMTS competition falls right about at this dividing line, so any decrease in price will open up a comparatively large number of new markets.

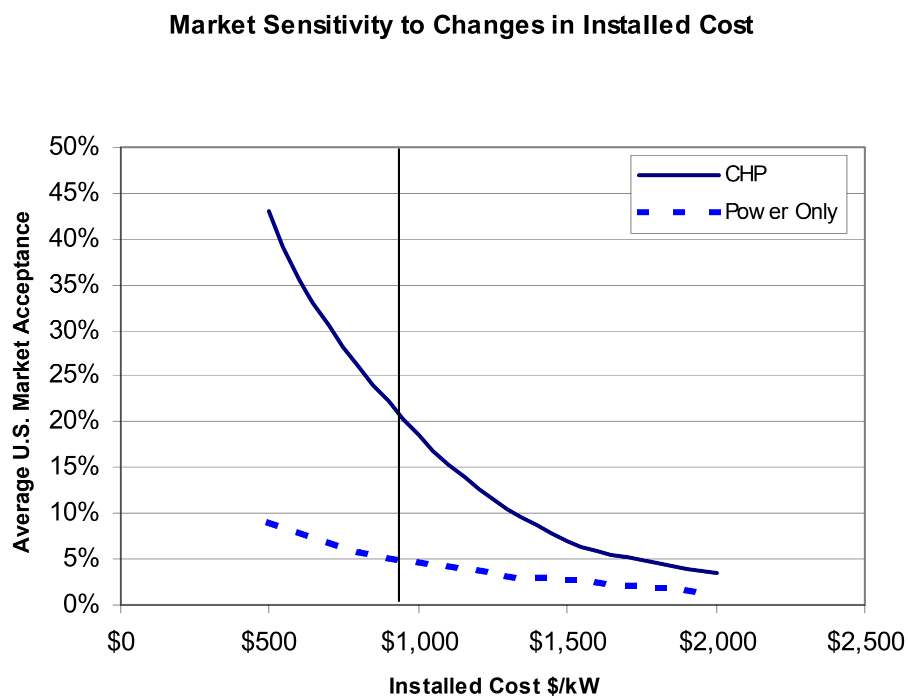


Figure 4.10 Economic Market Share as a Function of AMTS Installed Cost

Similar results can be seen as the other AMTS performance factors are varied. **Figure 4.11** shows the market sensitivity to changes in O&M cost; **Figure 4.12** shows the market sensitivity to changes in electrical efficiency.

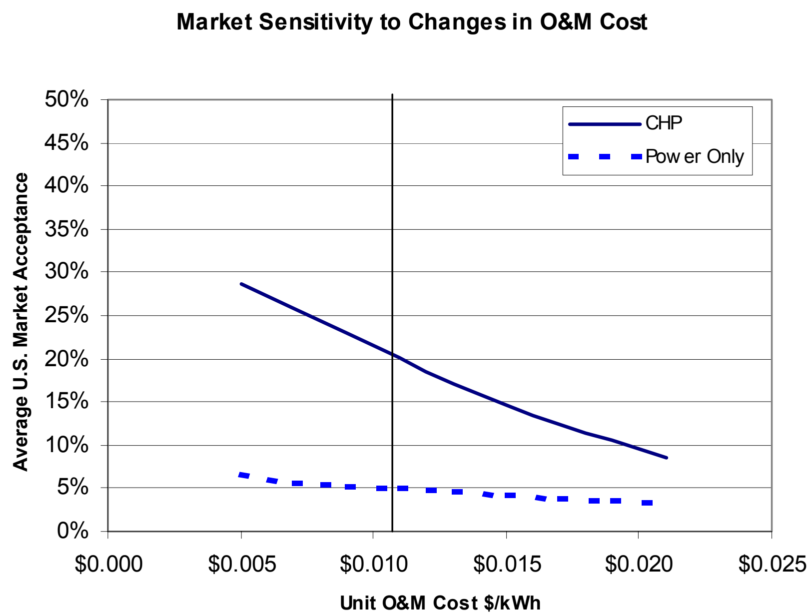


Figure 4.11 Economic Market Share as a Function of AMTS O&M Cost

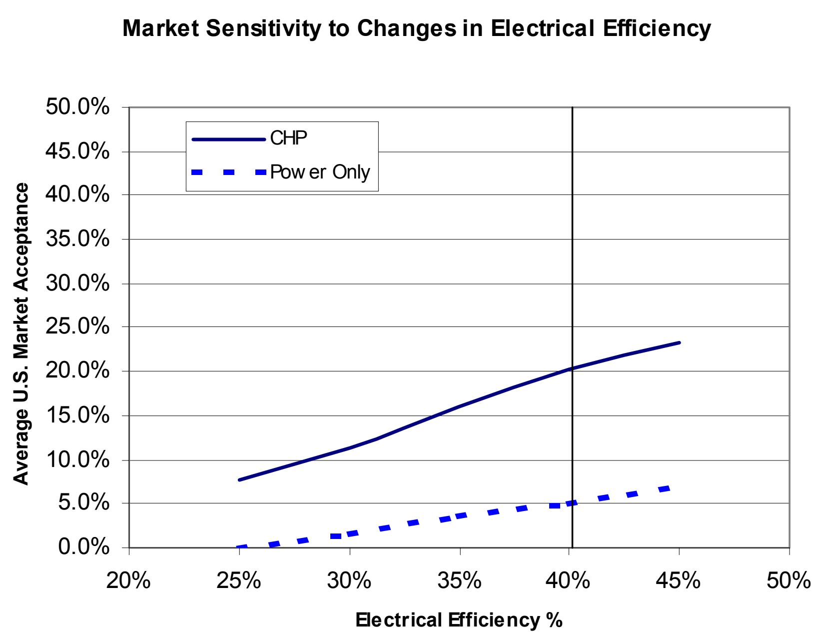


Figure 4.12 Economic Market Share as a Function of AMTS Electric Efficiency

Achieving low O&M costs can have a big impact on the market acceptance, particularly for CHP, which is more competitive than power-only. For every 1 mill/kWh reduction in O&M costs achieved there will be about a 1.5 percentage point increase in economic market share. The effect is much lower in power only application; across the whole range shown, the power-only market increases from 3.5% to 6.7%.

Improvements in electric efficiency are also important, particularly in moving from the levels of current small DG equipment of around 25% up to the AMTS goal of 40%. This change nearly triples the economic market potential from 7.5% to 20.6% of the technical market. Further increases have a lower market impact for CHP. Electric efficiency improvements are comparatively more important for power only applications, though even at high efficiencies, it remains a niche market at below 10% of the total technical potential.

The cost of the fuel input is also very important to the net power costs from the AMTS. **Figure 4.13** shows the relationship between net power cost and input fuel price for the AMTS goals system. Net power cost from the AMTS varies in a linear fashion with changes in fuel price. Because fuel makes up only a portion of the net power cost, a 10% increase in fuel price results in a lesser increase in net power costs – 5.7% for power-only and 4.2% for CHP. The use of the thermal energy in CHP applications moderates the impact of increased fuel prices because the value of the displaced fuel use is at a correspondingly higher price as well. While the figure shows net power costs as the dependent variable, we can also look at this the other way. If consumer power prices go down by 10% -- the competitive fuel price for an AMTS DG system must go down by 24% to remain competitive in a power-only application, by 18% to remain competitive in a CHP application.

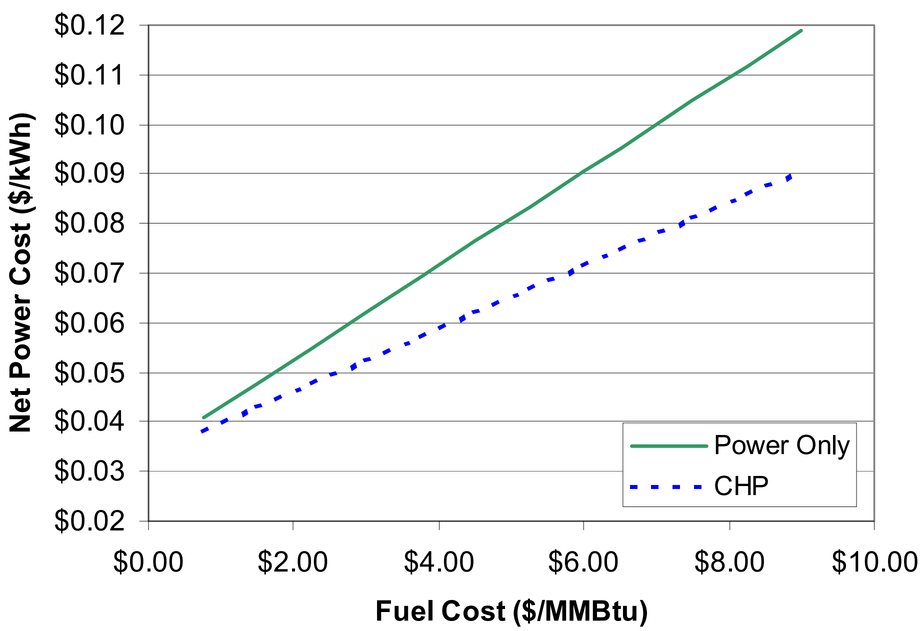


Figure 4.13 Sensitivity of Net Power Costs to Fuel Price – AMTS Goals

The fuel price/power cost relationship is important to the competitiveness of the AMTS. The economic market potentials in the previous section were estimated based on recent electricity and natural gas prices. However, the AMTS must compete in the future. The latest EIA reference forecast for natural gas and electricity prices are shown in **Figure 4.14**. After an initial drop from the recent high prices of 2000 and 2001, both natural gas and electricity prices are shown to rise (in real terms) only modestly. However, the EIA forecast shows that the 2001 prices used for the market analysis in the preceding section are higher than expected for the future. Comparing the 2001 to the 2015 prices, natural gas prices are forecast to drop by 23% and electricity prices by 10.7%.

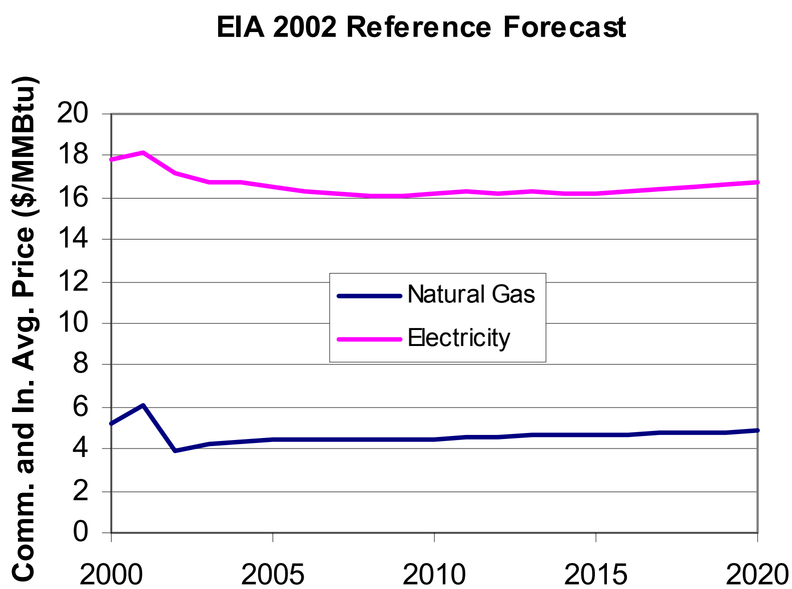


Figure 4.14 Forecast of Average of Commercial and Industrial Natural Gas and Electricity Prices

The state-by-state economic screening was rerun changing the prices according to the 2015:2001 price ratios defined above. **Table 4.6** shows the increase in economic market potential calculated using the EIA forecast price ratios instead of the 2000-2001 actual prices. The table shows very modest market increases for CHP applications and somewhat larger impacts for baseload power-only applications. This result is consistent with the net power cost vs. fuel price relationships shown in Figure 4.10. There is a greater reduction in net power cost for the same reduction in fuel price for power-only applications than for CHP applications. Unlike the traditional and direct CHP applications, the IES-BCHP applications shows an increase in economic market potential of 45-50%. It was assumed for the screening that peak power prices appropriate for summer air conditioning would not be reduced, thereby increasing the benefit for the avoided power used for cooling.

Table 4.6 Increase in Economic Market Potential Using EIA Forecast 2015 Electric and Gas Prices

Value Proposition	Increase in Economic Market	
	Interim Devel. %	AMTS Goals %
CHP New	6.3%	11.4%
CHP Retrofit	3.4%	14.4%
Direct CHP	2.3%	9.3%
IES-BCHP New	13.3%	46.5%
IES-BCHP Retrofit	7.9%	54.3%
Base (Retrofit plus New)	24.9%	21.2%

Note: Gas prices 77% of base case, electricity prices 89% of base case

Another factor that affects the economics of the AMTS in CHP applications is the degree to which the thermal energy is effectively used. *Thermal utilization factor* is defined as the share of the available thermal energy out of the heat recovery section that is used productively on-site. To a large extent, this factor will depend on the application characteristics. **Figure 4.15** shows how changing the thermal utilization factor changes the net power cost for the AMTS goals system in a new CHP site. At 100% thermal utilization, the net power cost is $0.069/kWh. If the site uses only 40% of the available thermal energy, the net power cost rises to $0.084/kWh. **Figure 4.16** shows the hypothetical market response to changing the thermal utilization factor in the market screening. In our base case screen, we assumed an 80% thermal utilization factor. This was chosen as a good overall estimator. In industrial applications it might typically be higher, in commercial applications it could be lower. Even though thermal utilization factor has a linear effect on net power cost, the impact on the economic market rises significantly when thermal utilization increases above 40%. Unlike the earlier market sensitivities to AMTS performance factors, Figure 4-16 does not represent a controllable variable for the AMTS developers, but rather a market uncertainty. In this analysis, the technical market potential for CHP was based on a threshold 80% thermal utilization. Relaxing this assumption would increase the technical market potential, but decrease the economic market acceptance. In very high cost markets, like the Northeast, it may be economic to pursue CHP applications with lower thermal utilization. In the lower cost markets, these applications would be uneconomic.

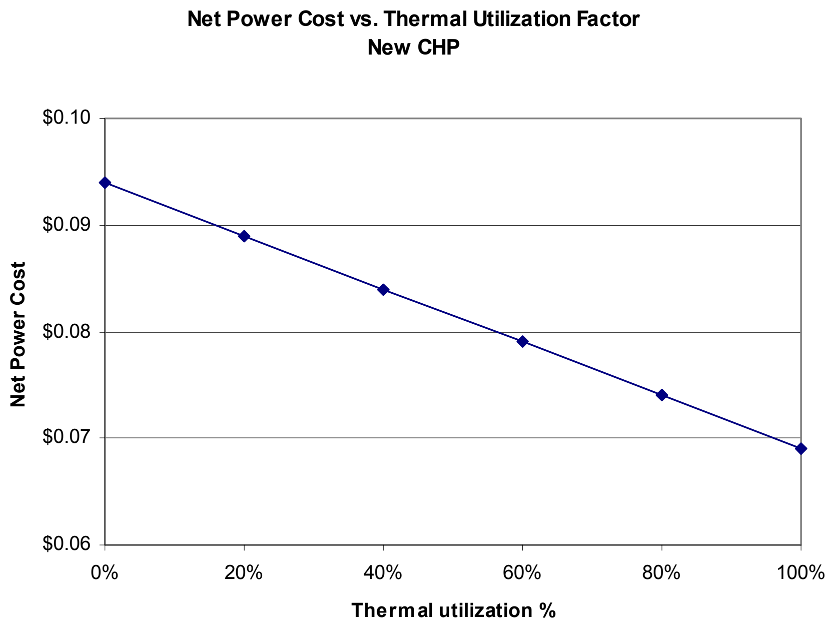


Figure 4.15 Net Power Cost as a Function of Thermal Utilization Factor

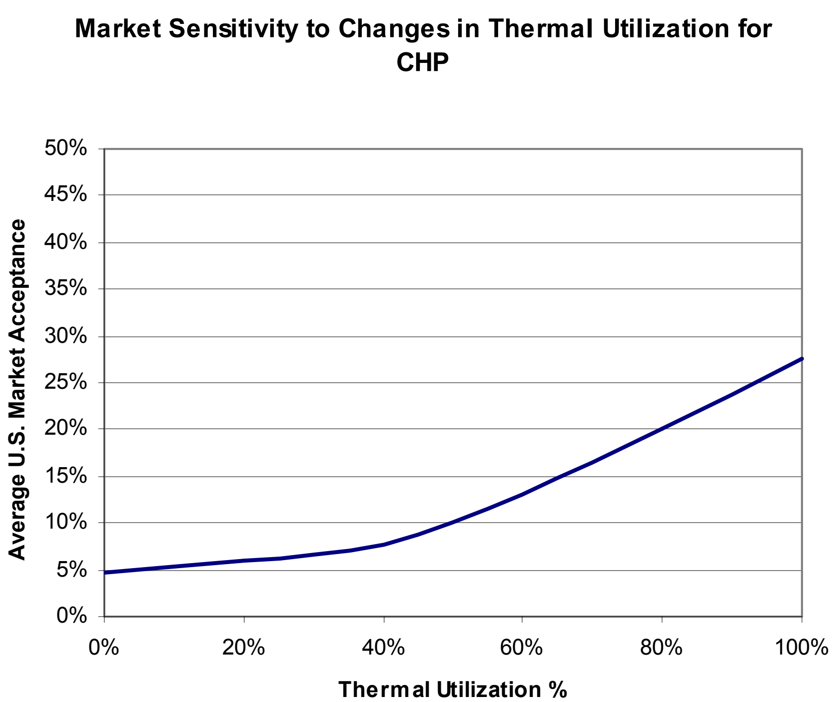


Figure 4.16 Hypothetical Market Response to Changing Thermal Utilization Factors

SECTION 5 – CRITICAL MARKET DEVELOPMENT FACTORS

5.1 Competitive Product Marketing

The competitive economics of advanced reciprocating engine (RE), microturbine, and fuel cell products for stationary applications are described in this section. **Figure 5.1** shows the comparison of these technologies in three applications: peaking, power only baseload, and baseload CHP. The cost and performance parameters used in the figure are summarized in **Table 5.1.**

The nature of fuel cell technology – high capital cost and high efficiency – make it less suitable for peaking applications than either RE or microturbines. In baseload applications, the advanced versions of fuel cell, microturbine, and RE technology all appear to fall in a competitive range with each other. The fact that these technologies are all so tightly grouped in the continuous power only and CHP applications says more about how these estimates have been derived than about the technologies themselves. All of these technologies are being supported with DOE funding and the program goals for each technology were defined through a coordinated planning process to provide a competitive product. Other than the fact that there is agreement about what this competitive target needs to be, really understanding how these technologies will perform in the remains to be seen. To emphasize this issue, Figure 5.1 also shows the cost levels for fuel cells if efficiency targets are met but current high costs for equipment are not reduced. Cost reduction, especially for fuel cells, is a critical factor.

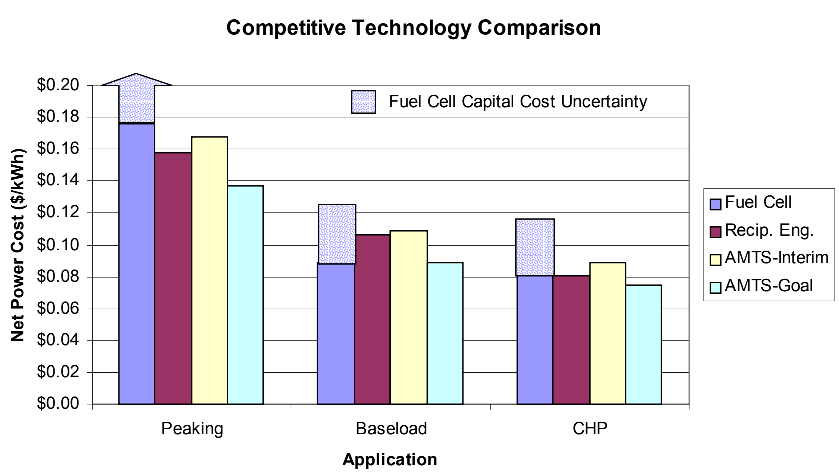


Figure 5.1. Comparison of Power Costs from Advanced DG Technologies

Table 5.1 Summary of Competing Technology Specifications

System Parameter	Units	Peaking	Base Power	Base CHP
Advanced Fuel Cell				
Capital Cost	$/kW	$1,500-$3,000	$1,500 - $3,000	$1,700 - $3,200
O&M Cost	$/kWh	$0.0091	$0.0091	$0.0091
Overall Efficiency (HHV)	%	49.5%	49.5%	74.2%
Net Power Cost	$/kWh	$0.176 - $0.298	$0.089 - $0.124	$0.082 - $0.118
Reciprocating Engine SI				
Capital Cost	$/kW	$880	$880	$990
O&M Cost	$/kWh	$0.0137	$0.0137	$0.0137
Overall Efficiency (HHV)	%	30.6%	30.6%	70.1%
Net Power Cost	$/kWh	$0.1620	$0.0917	$0.0653

There are some qualitative statements that can be made about how these technologies will compete in the future:

- Timing is a critical issue. The first milestone will be to achieve the performance goals and the next milestone will be to bring the costs down to the target levels. The current DOE sponsored development programs and developers own goals call for rolling product out in the next 1-5 years. This early market entry product will show performance enhancements, but costs will probably not be at final target levels. While the development goals all emphasize the next five years, there is a general belief, that fuel cells will require a longer development and maturation process than either RE or microturbine technology. In the case of RE technology, new technology will seamlessly be added to existing product lines as developments are proven. The base RE product is already a mature product with in-place production and cost structure. Costs for the AMTS will probably come down to target levels a few years after product introduction. In the long term, microturbine/fuel cell hybrids will enhance the continuous power only market.
- Emissions are another critical issue. Fuel cells at a cost premium will find niche markets that require extremely low emissions. Microturbines will have a competitive advantage compared to RE technology in California and the Northeast due to a more attractive emissions profile. While not quite as clean as fuel cell technology, the AMTS will be more cost competitive in a broader range of applications.
- Application suitability is the last key issue. Fuel cells will be inappropriate for intermittent duty and peaking applications. The AMTS will have an advantage compared to both fuel cells and RE technology in fuel flexibility for landfill, biomass, digester gas, and oil field applications. RE technology will maintain its superiority in straight standby applications and emergency applications, but these installations will not have the multi-use capability that an AMTS installation would have due to the high emissions of standby RE equipment.

5.2 Competitive Business and Market Approaches

There has been a tremendous amount of activity in the area of small power generation: manufacturer alliances and consolidation, regulatory changes, R&D in new technologies, and increased market development.

For purposes of discussion we can divide the competing developers/manufacturers into four groups:

1. Major, full line RE manufacturers with worldwide market presence (e.g., Caterpillar, Cummins, MTU)
2. Niche RE manufacturers with selected geographical and/or application strengths (e.g., Cooper, Fairbanks Morse, Daewoo)
3. Large well funded new technology developers (e.g., Ballard, Capstone, Siemens-Westinghouse)
4. Small new technology developers. (e.g., Ztek, Anuvu, ALM Turbines)

The business strategy of each of these manufacturer/developer types is described in this section.

Major Full line RE Manufacturers

The major companies such as Caterpillar and Cummins in the U.S. and companies like MTU in Europe have been engaged in a strategy of globalization and acquisition over the last several years. These major companies are acquiring niche RE manufacturers to extend both their geographical reach and their product reach. For example, Caterpillar acquired MaK in Europe to strengthen their market position in Europe and to move into large, heavy-duty diesel and heavy oil machines. Cummins launched a JV with Wartsila to both strengthen their worldwide sales and to provide larger, SI product.

Another strategy that big players are using is vertical integration through acquisition of generator manufacturers and packagers such as Cummins' merger with Onan and Caterpillar's acquisition of Kato and F.G. Wilson.

The big and small RE manufacturers are also becoming more adept at political action to promote industry-wide initiatives that will expand the market for DG such as the *CHP Initiative* and to secure funding for R&D in advanced technology – the ARES program.

A final piece of this strategy, and key to the emerging technology developers, is the interest shown in acquiring marketing, development, and manufacturing interests in emerging fuel cell and microturbine products. The major companies are shifting their focus from providing "cast iron" to providing prime-mover and power solutions to customers.

Niche RE Manufacturers

The niche manufacturers are being acquired by the majors for their strengths within their individual spheres of influence. Some of these niche players are quite large and rival the majors in market share within their individual markets. This is especially important to consider for those niche manufacturers that compete in the markets of interest to the AMTS. Small engine makers are becoming more aggressive at targeting stationary power applications. Much of this product is packaged and developed by OEM manufacturers of gen-sets and other power products.

The small independent producers may be subject to further consolidation – either struggling to remain independent or shopping themselves around for the best buyer. However, many niche RE producers for the stationary market are actually part of huge automotive or industrial conglomerates like (Ford Power Products, IVECO, Volvo, and virtually all of the Japanese makers.) Most of the automotive related companies have spent little of their resources focusing on stationary applications.

Large, Well Funded Developers of Emerging Technologies

The market strategy for both the fuel cell developers and the microturbine manufacturers with respect to the stationary market is very similar.

The basic approaches can be summarized as follows:

- Multiple product and technology paths to provide market coverage including FC/MT hybrids
- Strategic marketing/distribution alliances with major power systems providers: GE, Caterpillar, Cummins, MTU, UTC, Siemens
- Strategic alliances with major energy companies: GPU, PPL, and Southern
- Contract Engineering firms also being used for market development
- International tie-ins to Japan and Europe
- Capitalizing fully on government funded RD&D opportunities and product subsidies
- Development of step out products -- reformers, H2 generators to reduce risk and increase sales

One aspect of the larger, publicly funded companies like Ballard, FuelCell Energy, and Capstone is that, while many are still well-funded, they are under tremendous investor pressure to get product out in the market. Also, their approach to the market must rely on large penetration of product in multiple markets. The penetration requires not only continued product development, but also a fundamental shift up in the current markets for small stationary power systems. Some companies are trying to diversify into current markets and technology to provide near term revenues. Ballard, for example, is getting into reciprocating engine package development with Ford Power Products. This strategy will allow them to strengthen their revenue position, develop marketing strength, and provide additional outlets for the electronics components used in their fuel cell package.

Some developers are part of major corporations like Ingersoll-Rand, Siemens-Westinghouse, General Electric, and United Technologies Corporation. These companies would seem to benefit from the technical expertise and financial strength of the parent company. However, in the case of Allied Signal microturbine technology, when it was sold to Honeywell, its outlook and profit potential were evaluated based on different criteria – and the venture was shut down. These large players are less likely to put as much resources into a speculative market. The reality of business is that market leaders are not always the most innovative. A large company with a high degree of market power can let a smaller, more innovative company take the initial risks. If the product and market prove out, the large company can jump in either through acquisition or accelerated development. This attitude seems to be playing out in the stationary power market. The big players are hedging their bets with involvement in advanced technology, but not committing huge resources yet.

Niche Developers of Emerging Technologies

The smaller developers are trying to follow the same strategy essentially as the bigger developers: expand product line, develop ancillary products, capture public development funds, develop manufacturing, distribution, and marketing relationships with the market leaders. However, these companies are often little more than R&D houses with no track record in commercial product launch. Some of them are doing innovative work. If they are successful they will be bought out, and if they are not immediately successful, they can survive almost indefinitely on $1-2 million per year in contract R&D funds. They often map out niche markets. Coupled with low overhead, a successful result could be possible with sales in the 10s to the 100s per year. This is more true for fuel cell systems than for RE or microturbine developments as there needs to be a large market somewhere for the prime movers (such as the truck and bus market for engines and the truck market for turbocharger rotors) to be economic for packaging into the new application.

Marketers, OEM Packagers, and Value-Added-Resellers

These companies are not competitors, but there is a lot of competition among the developers to establish as many relationships as possible with these companies that represent applications engineering expertise and contact with the customer. Restructuring in the gas and electric power industries has created tremendous increase in well-financed affiliated companies with engineering and market focus – such as NiSource, Unicom, Southern, GPU, etc. These companies are getting into packaging, product development, and marketing, and have access to financing, fuel contracts, and other aspects necessary to complete a stationary DG project. These companies are a good source of expertise and funding for emerging technology developers. However, the emergence of unregulated utility affiliates has occurred only in the last several years; and their ability to successfully market stationary DG systems, and other innovative energy technology, remains unproven. These companies can either enter into exclusive relationships, or they can serve as a conduit for competing technologies – using their applications expertise and customer contacts to select the best technology for the application.

Engineering firms with a specific focus in particular markets such as water treatment, landfills, oil and gas field systems have provided a good outlet for emerging technology developers to approach these early-entry, niche markets. Again, these firms may be interested in a variety of competing products or they may want to package exclusively with a preferred vendor, at least within, the boundary of single technology.

OEM packagers of gen-sets are another potential source of applications expertise, distribution channels, and customer contacts. OEM packagers enter into specific agreements with selected suppliers. In spite of this apparent fit, and the interest that has been shown by some, the active development of the stationary DG market requires a different structure and focus than the competitive "spec-bid" approach used in the market for standby gen-sets.

There has been quite a lot of activity by both the established manufacturers and the developers of emerging technology in reaching out to as many of these market channels as possible. As these relationships have developed, additional relationships will become more limited because of existing competitive agreements or a decision on the part of the other big players that their existing agreements adequately cover their technology and market needs.

5.3 Market Barriers

While many analysts predict a growing role for distributed generation over the next 10 years, small on-site generation has historically faced severe market and regulatory barriers. These include utility practices and electricity rate designs that discourage on-site generation, lengthy and costly environmental permitting and siting processes, high transaction and installation costs, and high customer hurdle rates for energy related investments. The barriers to market development can be grouped into four major categories:

- Utility interface and access to the market
- Permitting and siting issues
- Financial issues
- Market/Customer Issues.

Utility Interface

An on-site generation system can be designed to serve the customer's electric power needs without connecting to the local utility distribution system. However, it is usually more cost-effective to size the on-site system to meet a portion of the user's power needs and to have the user physically connect with the local utility system for supplemental power needs beyond their self generation capacity and/or for standby and back-up service during outages or planned maintenance. In the past, many DG system developers have expressed frustration at the costly and confusing requirements placed in the way of system implementation. In some cases, utilities discouraged on-site generation by offering negotiated rate discounts only after DG project planning is underway. In a restructured electric power industry, the value of on-site generation to the generating customer, the utility, and the ratepayer in general needs to be re-examined so that pricing and operating rules fairly reflect the benefits of on-site generation.

Grid Interconnection

The optimal economic use of DG for most customers requires integration with the utility grid for back-up, supplemental power needs, and, in selected cases, for selling generated power. Key to the ultimate market success of small on-site generation is the ability to safely, reliably and economically interconnect with the utility grid system. However, grid interconnection requirements for self-generators, as they exist today, are a significant barrier to more widespread economic deployment of smaller DG systems.

Interconnect requirements for on-site generation have an important function. They ensure that the safety and reliability of the electric grid is protected, and the utilities have ultimate responsibility for system safety and reliability. For the utilities, there are three primary issues. First, the safety of the line personnel must be maintained at all times. Utilities must be assured that DG and other on-site generation facilities cannot feed power to a line that has been taken out of service for maintenance or as the result of damage. Second, the safety of the equipment must not be compromised. This directly implies that an on-site system failure must not result in damage to the utility system to which it is connected or to other customers. And third, the reliability of the distribution system must not be compromised.

These basic concerns are important and legitimate. However, non-standardized, out-dated, and in some cases, overly stringent interconnect requirements have long been a barrier to widespread deployment of small on-site generation technologies. Interconnect requirements vary by state and/or utility and are often not based on state of the art technology or data. Compliance often requires custom engineering and lengthy negotiations that add cost and time to system installation. These requirements can be especially burdensome to smaller systems (i.e., under 500 kW). Non-standardized requirements also make it difficult for equipment manufacturers to design and produce modular packages. The lack of uniformity from state to state, as well as from utility to utility within a given state, lessen the economic payback for on-site generation, no matter the market segment or type of end-use application.

In addition to the absence of a cost-effective uniform standard, another major challenge facing DG purchasers is the time consuming and costly interconnection process with unmotivated utilities. This uncertainty may stem ultimately from a lack of incentive for the utility to provide predictable, efficient methods for interconnection of on-site generation.

Currently, proactive government in Texas, California, and New York are focusing on interconnection issues and are moving toward the development of more equitable standards and contracting models. The results from these efforts should help to define the issues more clearly, and industry-wide standards organizations, most notably the Institute of Electrical and Electronic Engineers (IEEE) will be the venue for ratifying improved standards on a national basis. The Department of Energy is lending its support to the development of uniform and equitable interconnection standards through the IEEE.

Standby/Back-up Charges

On-site generation usually requires back-up power to cover downtime for routine system maintenance or for unplanned outages. Standby rates are a fixed monthly charge for reserved generation and distribution capacity to provide back-up power. Generally, standby service is billed, based on the rated capacity of the self-generation unit, or customer peak demand, whichever is lower. As an example, an on-site DG system in Southern California Edison's territory will currently pay $6.40/kW for standby service. This rate is essentially equal to the facilities related component of the customer's normal demand charge.

Should a customer actually require back-up power, additional charges are invoked that reflects the cost of supplying power to a self-generation customer during an outage. These back-up charges often contain an additional demand charge. As an example, California utilities have high monthly electric demand charges that are levied against self-generation in their entirety even if only needed for a brief time period during an unscheduled outage in a month (even as briefly as 15 minutes). This is in addition to an energy charge that is based on kWh used during the outage. Unreasonably high costs for these services (standby rates and back-up charges) have been a barrier to on-site generation in the past. As restructuring proceeds, these charges as currently configured may not necessarily reflect a utility's actual cost, nor do they necessarily reflect the diversity of DG resources on the system.

A fair calculation of the true costs of these services and competitive means for supplying them are essential to ensure the economic implementation of on-site generation. However, state regulators struggling with the larger issues of restructuring are in general unaware of the importance of standby fees and back up charges on the economic viability of on-site generation. Education and outreach are needed to bring this issue to the forefront in rate discussions. Alternative approaches such as designing standby fees based on the statistical probability that some level of on-site generation on a system will be operable even if individual units are down need to be evaluated and promoted. Similarly, unreasonable performance requirements on customer owned units can easily negate the customer value of distributed generation and must be avoided.

Stranded Costs

Under most state restructuring plans utilities are being permitted to recover stranded assets that were incurred on behalf of their customers under previous regulatory arrangements. In many states, tariffs for stranded asset recovery are non-bypassable, and customers installing on-site generation pay a fee on the kWh they generate as well as purchase, or they may be charged a one time exit fee equal to their share of the expected stranded cost if they elect to leave the grid. Other states have decided to charge on-site generators exit fees for potentially unused distribution assets even after stranded generation and transmission assets are completely recovered through the restructuring transition period. However, these same states do not attempt to apply such charges to kWh reductions resulting from demand side management or other energy efficiency investments by the customer. Some utilities have raised the possibility of a new "wire-bypass" charge to recover what they perceive will be stranded distribution charges in the event a customer installs self-generation. Application of these charges to efficient on-site generation projects can significantly impact the economics and delay widespread implementation of DG.

Regulators are generally concerned with fairness toward all ratepayers and reluctant to subsidize one group at the expense of other. However, certain societal benefits such as environmental protection, regional economic development or energy efficiency may justify special treatment. States such as Illinois, Massachusetts, Texas, Ohio and New Jersey have recognized the potential benefits of distributed generation and have either waived or partially exempted various forms of on-site generation from competitive transition charges or fees.

Permitting and Siting Issues

On-site generation must comply with all applicable local zoning and health and safety requirements at the site. These include rules on air and water quality, fire prevention, fuel storage, hazardous waste disposal, worker safety and building construction standards.

The local agencies interested in the siting of on-site generation units include fire districts, air districts, water districts and planning commissions. Therefore, the installer of a DG unit may need to pay for and obtain permits, or variances from permits, inspections, and approvals from many different local agencies. In addition, one or more of the agencies may require additional equipment or impose special operating standards as a condition to granting approval for the unit. Depending on the basis for the requirements, the local agency may or may not have discretion to modify the terms of the approval or negotiate with the installer for a variance.

Both engaging in the local permitting process and complying with the technical requirements coming out of the process can impose significant costs on a self-generation installation. The costs depend on the kind of unit being installed, how sensitive the local area is to the environmental impact, how familiar the local agency is with the installation, and how the nearby neighbors feel about the installation.

Environmental Regulations

As distributed generation penetrates the electric power infrastructure, its potential impact on the environment will gain more attention. On-site generation, and most particularly combined heat and power (CHP), has the potential to reduce overall emissions of both criteria pollutants (NO_x, SO_2) and greenhouse gases. The use of on-site generation by customers to supply some or all of their electricity will displace the need for power purchases and offset emissions at the central station plant. CHP also displaces emissions from the existing boiler/burner at the site.

The 1990 amendments to the Clean Air Act created what is known as "Title V" permitting and amended "major new source" review. These requirements apply to any new or modified source and depending on the severity of the local air quality district, a major source is defined anywhere from 250 tons/yr down to 10 tons/yr for NO_x.. In the one "extreme" ozone non-attainment area in the U.S.—Los Angeles—a generator would be subject to new source review if it emitted more than 10 tons per year of NO_x or VOC. In "severe" non-attainment areas such as New York City or Chicago, generators can emit up to 25 tons per year before tripping New Source Review.

Beyond the federal regulations, states are left to add additional regulations. In practice in New York City, engines are automatically exempt from permitting if they are smaller than about 150 kW. Microturbines are exempt if they use less than 10 MMBtu/hr fuel. This is about the amount of fuel an 800 to 900 kW generator would use depending on its efficiency. Establishing a requirement for an air permit does not mean that emissions will have to be controlled. In New York if a generator is large enough to require a permit, but not large enough to be governed by Title V, the generator may have to monitor its emissions, but, will not have to restrict them.

California has taken a different approach in the Los Angeles area establishing lower size requirements for permitting and emissions restrictions. The South Coast Air Quality Management District's (SCAQMD) rules require engines down to about 40 kW (50 hp) to limit emissions of NO_x to about 1.6lbs/MWh (.15 gm/hp.hr) and CO to 21.6/lbs/MWh (.6 gm/hp.hr).

Currently engines below 50 hp are exempt. Microturbine systems less than 3mmbtu/hr input (or 200 hp) are currently exempt from emission regulation in SCAQMD. Larger microturbine systems would be required to achieve BACT (Best Available Control Technology) and if total emissions exceed 4 tons/yr would also be subject to RECLAIM.

These regulations are based on limiting the emission of criteria pollutants per unit of fuel input or their concentration in exhaust streams from specific sources. This approach does not credit on-site generation with the emissions reductions associated with reduced consumption of electricity from the grid or for displaced emissions from existing on-site sources. In addition, regulatory emphasis has focused on new sources, which theoretically can more easily meet stringent regulations. In fact, existing facilities receive favorable treatment under existing air pollution regulations, being "grand fathered" under the Clean Air Act. This approach penalizes installation of new power generation facilities, including on-site generation systems.

The Environmental Protection Agency (EPA) is considering ways to respond to these issues, including the proposed use of output-based standards that value the benefits produced per unit of air emissions and would therefore credit increased efficiency, and recognition and credit for displaced emissions from grid generated electricity. However, changes to EPA guidelines do not come quickly, and if enacted, must then be implemented by state and local agencies, adding additional time before market impact.

Furthermore, both California and Texas have established long-term goals to regulate DG and Central Plant emissions on a common basis. The details have yet to be worked out, but the likely outcome will be to increasingly challenge the environmental signature for new DG.

Environmental Permitting

A notable environmental barrier for on-site generation is the air quality permitting processes and regulatory requirements. The air quality permitting process for various technologies can be long, complex and costly. The complexity of permitting results from regulatory requirements that differ among the various air districts. The lengthy permitting process results from site-specific analysis and ever changing BACT levels. The costly component of air quality permitting not only results from the lengthy permitting process but the potential need to install more costly controls and/or the need to purchase emission reduction credits (ERCs) to offset emissions.

Thus far, microturbines have been exempted from permitting in certain regions, and pre-certification discussions are ongoing as well. Pre-certification would not be for purposes of automatic permitting, but would help expedite permitting by certifying equipment performance at the factory and eliminate the need to individually demonstrate equipment performance for each permitting application.

Site Permitting

One of the most significant impediments to deployment of on-site generation is inconsistent and location-specific process, rules, regulations, filing requirements, procedures and jurisdictions affecting general siting and permitting. There are a wide variety of criteria and jurisdictions that must be addressed beyond air emissions including water impacts, noise, land use, visual impacts, fire, safety, fuels, and hazardous materials. Lack of familiarity with on-site generation technologies, and applications and absence of pre-certification for criteria of interest, result in site-specific negotiations that can be time consuming and costly, particularly for smaller generation systems.

Financial Barriers

Tax policies can significantly affect the economics of investing in new equipment such as on-site generation. On-site generation systems do not fall into a specific tax depreciation category. On-site generation equipment can qualify for one of several categories depending on configuration and ownership, so that the resulting depreciation period can range from 5 to 39 years. Existing depreciation policies may foreclose certain ownership arrangements for on-site generation, increasing the difficulty of raising capital and discouraging development.

The distributed generation community believes that a 5 to 7 year depreciation schedule more accurately reflects the economic life of on-site generation equipment, and the Administration has recognized the negative impact current policy can have on the development of the market. DOE and EPA have been working with the Administration and the Department of Treasury to review existing depreciation categories for on-site generation equipment and to consider investment tax credits for CHP. Treasury is considering allowing on-site equipment in buildings to qualify for a 15-year depreciation schedule, similar to on-site generation equipment in industrial applications and significantly shorter than the current 25 to 39 year depreciation schedules for building applications.

Market Issues

While interest in distributed and on-site generation has grown, a number of market-related barriers exist that constrain market acceptance:

- On-site generation is still not considered part of most users' core business and, as such, is often subject to higher investment hurdle rates than competing internal options.
- Small-distributed generation technologies, in particular micro turbines, have improved significantly since the early 1990s and are gaining greater market acceptance. Most users, however, remain unaware of the cost and performance benefits that may be available.
- Customer requirements and needs are yet to be fully analyzed and understood by equipment manufacturers and developers.

5.4 Customer Perceptions

The criteria for a customer to implement on-site generation or any energy management strategy are complex and becoming even more complicated as the industry evolves. Onsite has had the opportunity to deal directly with on-site generation customers during the course of its core business. Key issues from the customer's perspective are outlined below.

Customer Issues: Economics

- Economic issues are paramount for customers that have or are considering on-site generation. Economic attractiveness can often be improved by integrating the generation system with an overall energy management system efficiency upgrade.

- The utility or main electricity provider has a powerful role in economics. Changes in utility rates that could obsolete a plant prematurely are a concern. This situation has occurred for many systems in California. Also, different rate structures can change the operating strategy from CHP to utility dispatch in a standby mode.
- Systems that do not live up to technical specifications or that have prolonged start-up issues adversely affect the system attractiveness.
- In addition to saving on energy costs, avoiding the very high costs of outages is an overriding concern for critical manufacturing facilities, data centers, and hospitals.
- Many customers do not want price volatility in energy and would prefer price stability even if at a premium.

Customer Issues: Restructuring

- Prior to California's energy debacle, most Industrial and commercial customers believe that electric industry restructuring would generally lower their power costs, increase price volatility and reduce reliability. Since the California crisis, customers have become much more aware of the magnitude of price and reliability risks in an open market.
- On-site generation is seen as a tool that can be used to apply leverage to power suppliers and a means of providing operational flexibility to either buy or generate power. On-site generation is also seen as a means to preserve reliability.
- Some customers feel that restructuring will enhance the value of on-site generation by providing opportunities for power sales and wheeling.
- There is much uncertainty and a "wait and see" attitude that is keeping customers from moving aggressively on either energy management or on-site generation investments.

Customer Issues: Product Requirements

- Customers vary in technical sophistication. Most would like a single point of accountability on energy projects such as in a "design build" contract.
- The control system is very important. It should be transparent in operation and robust -- minimizing "nuisance trips" and other problems that can add significantly to staffing requirements.
- Customers also want the system to perform to design specifications -- heat rate, capacity, and maintenance required.
- Reliability is an important requirement both in terms of an overall system, but also in terms of the availability of an individual genset.
- Maintenance has been an issue for small DG, in part due to the lack of qualified facility engineers at smaller commercial and industrial sites, and to the lack of comprehensive service contracts by some small DG packagers and suppliers.
- Noise control is often an issue that has to be addressed in the placement and design of a system. Historically, for engine systems, it has been more common to site them inside buildings than in enclosures outside.
- Staff training is an important issue. Lack of effective support by the factory and the dealer leaves a bad impression and can lead to operator mistakes and unnecessary downtime.

Customer Issues: Hassle Factor

- Dealing with the electric utility is still the main complaint. The biggest problem is getting approval of the single line diagram for interconnection and subsequent testing and approval of the system. This is particularly concerning for smaller systems such as microturbines.
- Excessive paperwork requirements for interconnect design and testing and permitting is also cited as a problem
- Past experiences with small DG have been with reciprocating engines, which are perceived as high maintenance systems. Catalytic exhaust treatment systems are a particular issue.

5.5 Critical Market Factors

The future market for small on-site generation technology is difficult to estimate because the full economic impact of restructuring is not yet known. In most states, the rules for electric industry restructuring are just now being developed. How these rules are formulated and implemented will have significant impact on customer and utility interest in small generation. Critical factors for the future development of this market can be summarized as follows:

- Utility Attitudes - While restructuring is opening access to the grid, and promises to provide open competition in the future, the local utility's attitude towards on-site generation will still affect the extent of market development during the transition. Utilities that have capacity or distribution constraints and see on-site generation as a potential solution will be attractive market entry targets.

- Future Electric Prices – Initial customer expectations for electric rates to go down as a result of restructuring an are changing as a result of the California experience, deferring investment in technologies aimed at avoiding or reducing electric use. Customer interest in DG seems to be gaining momentum as a reliability and cost hedging tool.

- Rate Structures – Unbundling of rates into separately priced services will most likely reduce base load power costs and increase peak period prices. This will stimulate the demand for peak shaving. On the other hand, some utilities (Southern California Edison is an example) have proposed rates that shift more of the distribution costs into fixed charges. This type of structure will reduce the economic benefits of on-site generation. Monitoring the evolution of rate structures in target markets and the extent and pace of rate unbundling and time of use rates will help identify priority markets and promising regions.

- Reliability – Perceptions of increased reliability problems after restructuring may increase the demand for customer generation for emergency and back-up purposes. Unbundling of rates may also quantify the cost of increased reliability allowing project economics to capture the benefits of enhanced reliability.

- Stranded Asset Recovery – The key factor in competitiveness of customer generation over the next 5-10 years is the level and means of stranded asset recovery. Whether or not a customer can avoid these charges by putting in self-generation will be an important factor in the marketability of generation systems during the transition periods. Stranded asset recovery will be implemented differently in each state. Political and regulatory efforts are needed to encourage regulators to provide exemptions for technology that is in the public interest.

- Standby/Back-up Rates - The cost of back-up service can be critical in determining the economic viability of on-site generation. Individual state PUCs; have been slow to realize the impact of these costs on the economics of self-generation. Market development in certain areas may depend on a restructuring of these rates.

- Peak Power Programs – Interest in interruptible or curtail able load programs that utilize customer generating equipment with utility notification or dispatch will likely increase in the future to help blunt the effect of price volatility in the wholesale power market, such as those that occurred during the past three summers. Current programs are designed and implemented by the utility. In the future, programs may be implemented either by the *independent system operator* coordinating the wholesale power transmission system or by private *energy service providers* aggregating small generators.

- Energy Service Providers – Utility marketing affiliates and independent energy service providers are in a frenzy to lock up customers and products to gain a market edge. Many unregulated service providers are developing multifunction portfolios that include power and fuel marketing, risk management, energy facilities management, and small power generation technology and marketing. During this period, these energy service providers are receptive to new product marketing ideas and opportunities.

- Interconnection - Interconnect requirements vary significantly in their complexity and ease of implementation. Efforts underway at the national and state level (New York, California, Texas) to standardize requirements, allow pre-certification or type testing of equipment and reduce interconnect application and contracting complexity could be significant factors in reducing costs for small generators.

- Environmental Regulations - Local interpretation of air quality regulations could impact the viability of small DG systems. Long-term pressure will be on DG to keep pace with Central Stations technology.

- Customer Perception - Microturbine and fuel cell developers have generated enormous interest about distributed generation among policymakers and potential users. While this attention has had a significant benefit in raising the visibility of this market in these early stages, failure of these new technologies to perform as promised could have negative effects on long-term market development.

APPENDIX A – OVERVIEW OF THE DG MARKET

This appendix provides a brief overview of recent distributed generation (DG) market activity and provides a summary of potential applications and customer requirements. Particular emphasis is placed on small DG systems and microturbines and their role in the future DG market.

Manufacturer Shipments

There has been a significant increase in both the U.S. and worldwide sales of small generating equipment. Two categories of equipment make up virtually all of the current shipments: 1) reciprocating diesel, gas, and dual-fuel engines and 2) combustion turbines. *Diesel & Gas Turbine Worldwide* has published their private survey of manufacturer shipments for the past 23 years. This survey has some limitations because it does not include equipment below 1 MW capacity. While there are a very limited number of gas turbines available today that are less than 1 MW, there are a large number of reciprocating engine gen-sets below this size. In fact, the bulk of the unit sales fall into the area excluded by the *D&GTW* survey. The Gas Research Institute (GRI) attempted to define the less than 1 MW market for the same time period.

Reciprocating Engine Market

Orders for diesel, dual-fuel, and gas engine generators totaled 6,414 units worldwide for the 12-month period ending in May 2000, representing a 23 percent increase in activity over the previous year. A 22-year history of reciprocating engine electric power generation (EPG) orders is shown in **Figure A-1**.

The 1990s have brought on a six-fold increase in equipment sales. **Table A-1** shows the North American orders for reciprocating engine generators. There have been significant increases in the last three years in the 1.0-3.5 MW size range. There was an increase in orders of these units for standby service reflecting both year 2000 (Y2K) reliability concerns and also reliability in restructured electricity markets.

Table A-2 shows the breakdown of engine sales for North America in 1997. These figures include spark-ignited engines (SI) fueled with natural gas and LPG and diesel cycle engines fueled with diesel oil. According to this GRI data set, there were nearly 45,000 engines sold in North America for stationary applications. About 89 percent of these were diesel engines, most of which went into standby power applications. Natural gas engines make up 11 percent of the total, and, according to other industry analysts this share is continuing to rise. There are 40,000 engines sold each year in North America in the less than 500 kW size range. Looking at the 10 percent SI share in this size range gives some indication of the market for engines with more attractive operating values than the very inexpensive diesel standby configuration.

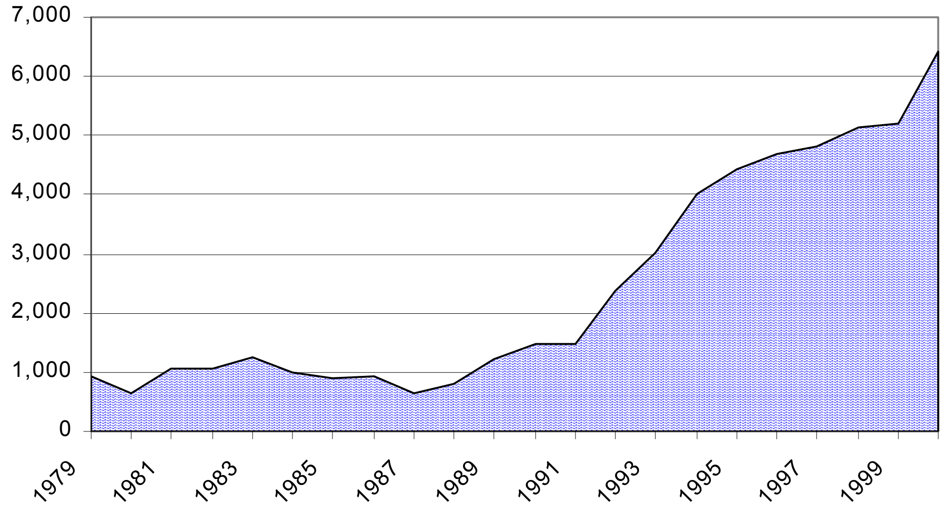


Figure A-1. Worldwide Orders for Reciprocating Engine Generators Greater than 1 MW

Table A-1. North American Orders for Reciprocating Engine Generators (> 1 MW)

North America						
MW	**1995**	**1996**	**1997**	**1998**	**1999**	**2000**
1.0-2.0	1,377	1,389	1,158	1,641	1,748	2,557
2.0-3.5	11	3	165	177	229	461
3.5-5.0	3	6	11	11	5	2
5.0-7.5			2	21	16	15
7.5-10			0	1		
10-15			1	5		
Totals	1,391	1,398	1,337	1,856	1,998	3,035

Table A-2. North American Sales for Reciprocating Engines (1997)

Output	Total Market*		SI Market**		Diesel Market**		SI Share
kW Range	MW	Units	MW	Units	MW	Units	%
<100	969	25,990	101	1,898	868	24,092	10.4%
101-300	2,080	12,186	234	1,491	1,846	10,695	11.3%
301-500	1,133	2,672	85	229	1,048	2,443	7.5%
501—800	909	1,425	120	198	789	1,227	13.2%
801-1200	1,493	1,478	241	293	1,252	1,185	16.1%
1201-2000	1,517	1,046	82	49	1,435	997	5.4%
2001-5000	322	115	81	31	241	84	25.2%
5001-10000	155	25	12	2	143	23	7.7%
Total	8,578	44,937	956	4,191	7,622	40,746	11.1%

* Dan Kincaid, "Technology Update: Reciprocating Engines," CADER and DPCA Conference, Powering the New Millennium, Sept. 13-14, 1999, San Diego

** Private Communication with Dan Kincaid, SI includes natural gas and LPG but not gasoline. Diesel excludes heavy fuel oil and dual fuel (both small numbers)

Combustion Turbine Market

The market for combustion turbines has experienced a similar growth over the past 22 years. From a fairly constant level of 400 units/year in the 1970s and 1980s, orders have tripled to over 12 units per year as shown in **Figure A-2**.

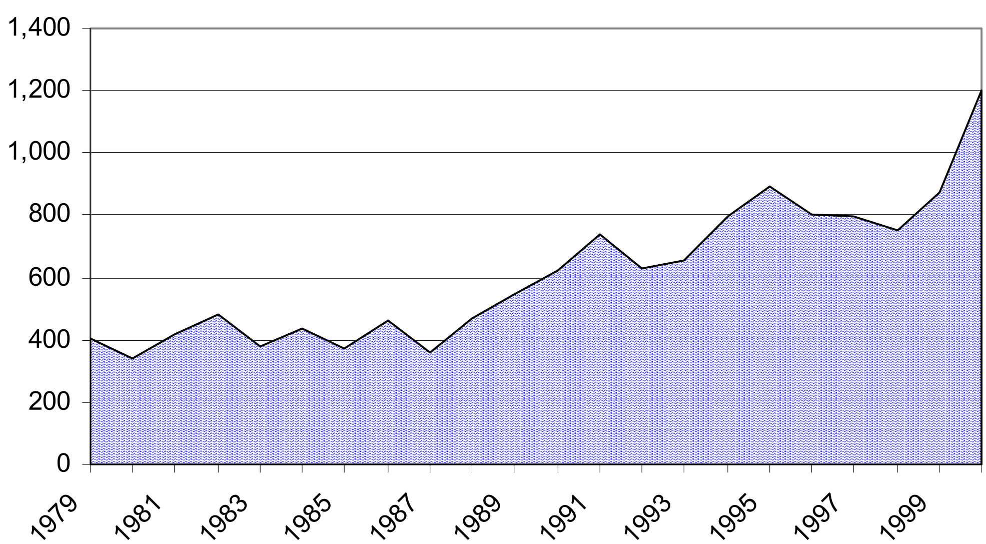


Figure A-2 Worldwide Orders for Combustion Turbines (Units)

These data include all turbines larger than 1 MW, and as such, include both DG class equipment and larger units that are in high demand now for merchant power and utility plants. North American sales are shown in **Table A-3**. While the overall turbine market is booming, the market for DG sized equipment (20 MW and under) is growing only moderately. There are 50-55 DG sized turbine sales per year, whereas the merchant plant and utility market is much larger. The decline in the 3.5-5.0 MW market size reflects the increase in capacity for popular models above 5 MW in rated capacity.

The small CT market is smaller than the small engine market primarily because there is not a standby market as there is for low-cost diesel engine gen-sets. Small turbine driven generators are often utilized in industrial and institutional combined heat and power projects because of the ability to generate high quality steam from turbine exhaust. The merchant/utility-sized market is exploding because of the ongoing restructuring in utility markets.

Table A-3. North American Combustion Turbine Orders

North America		
MW	**1999**	**2000**
1.0-2.0		4
2.0-3.5	1	
3.5-5.0	17	8
5.0-7.5	30	37
7.5-10		
10-20	7	4
Large CTs	307	462
Totals	362	515

Emerging Technologies

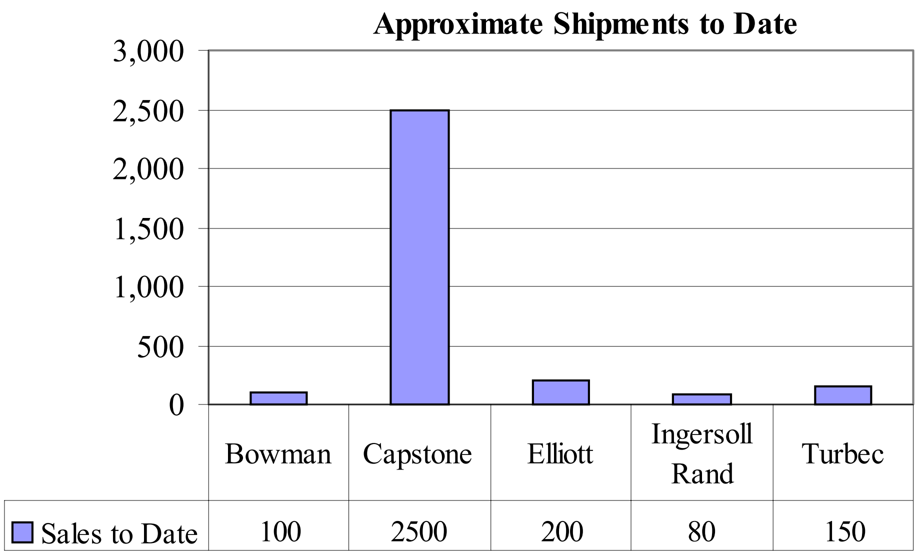
Combustion turbines and reciprocating engines represent almost the entire market for DG currently. However there are a number of technologies that are emerging into the market and are expected to play a larger role in the future of distributed generation: microturbines, fuel cells, and photovoltaic are three technologies that are the most prominent.

Microturbines

Five microturbine manufacturers have made initial market entry with worldwide total industry shipments of over 3,000 units[10] – shown in **Figure A-3**. Capstone, the largest manufacturer has 82% of this initial market. These five companies have been actively developing products and options, negotiating sales and service agreements with trade allies, and supporting initial market demonstrations. There has been some retrenchment in the market as sales have not grown as

[10] Tony Hynes, "DG and CHP Technology Overview: Microturbines," *DG and CHP in Federal Facilities*, Bowman Power Systems, Inc., Newport Beach, CA, May 13, 2003.

rapidly as developers and market analysts expected in 2000. Turbec has recently postponed plans to enter the North American market. Honeywell/Allied Signal had a major effort underway, and then dropped out of the market altogether. The remaining manufacturers/developers are continuing market development activities, but with lowered market forecasts for 2003.



Source: Tony Hynes, Bowman Power Systems, Inc.

Figure A-3. Cumulative Sales for Microturbines by Manufacturer

Fuel Cells

Fuel cells represent a class of technologies that produce power from electrochemical reactions like a battery that is fed with a continuous flow of fuel rather than with stored chemicals. Like microturbines, there is interest in both the stationary and transportation markets. Phosphoric acid fuel cells are the only type of fuel cell that is commercially available today. They are manufactured by ONSI, a subsidiary of United Technologies, and about 200 units have been installed to date, most of them with the help of government provided incentive payments to bring down the high first cost ($4,500/kW) of the units. Financial and industry analysts do not see this technology as having mass-market application, like microturbines. Rather, this generation of fuel cells is seen as a niche product for special applications: military, sensitive environmental areas, and high power quality applications.

There is considerable interest in the mass market potential of several new fuel cell developments including proton exchange membrane (PEM) (Ballard, Plug Power, Avista Labs), solid oxide fuel cells (SOFC) (Siemens Westinghouse, Global Thermoelectric) and molten carbonate (Fuel Cell Energy). While there have been some demonstration projects, none of these technologies have reached commercialization. Of the three, PEM technology is targeted at virtually the same size and markets as microturbine technology.

Photovoltaic

Photovoltaic uses solar energy to produce power. Photovoltaic power is modular and can be sited wherever the sun shines. These systems have been commercially demonstrated in extremely sensitive environmental areas or for remote (grid-isolated) applications. High costs make these systems a niche technology that is able to compete more on the basis of environmental benefits than on competition with grid power where it is available.

The market for solar power products was about $2 billion in 1999, representing production of about 200 MW of generating capacity. Total installed generating capacity was about 1,000 MW as of 1999. The top three companies in this market are BP Solarex, Kyocera, and Siemens. These three companies have a combined 50 percent market share.

Ancillary Technologies

There are a number of technology areas that will support the growth in DG markets. Communications and control equipment will be very important, especially in the development of automated operation and also in low cost utility interconnection and paralleling. Power electronics equipment is also very important to this market and particularly to the future success of microturbines that rely on this equipment to convert the output of their high-speed generators to 50-60 Hz power. Another class of equipment includes energy storage and uninterruptible power systems (UPS.) UPS systems are a growing market today and will be important in the future for the marketing of enhanced systems UPS systems that have expanded generating capabilities to take advantage of better economics of operation and to provide safety for longer outages.

The Banc of America estimates the current power quality market at $12 billion sales annually. Key market segments are as follows:

- UPS Systems – The UPS market is estimated to be $5.5 billion in 2000 and growing at about 15 percent annually. American Power Conversion is the leader in the less than 260 watts market segment and Liebert (a subsidiary of Emerson Electric) is the market leader for larger equipment
- DC Power Systems – This market is oriented toward communications and cellular applications. The market for DC power equipment was $3.5 billion in 2000 and growing at about 20 percent annually. Lucent and Liebert are major players in this market.
- Standby generation – Banc of America includes this market here. They estimate that the market equals $3.5 billion per year. Diesel generators are the primary technology, already discussed. Lead acid storage batteries are also included in this category.
- Reserve – Customers expect that a reserve capacity is available in the event of higher than anticipated demand.

- Back-up and Standby Service – Customers with their own generation need back-up power during periods in which their equipment is not operating due to unscheduled maintenance or forced outage,
- This equipment serves the needs of the fast growing market sectors, of data, banking and telecommunications centers.

Customer Needs and Applications

The manufacturer sales data show a growing market, but these data do not explain the types of applications that are being installed and the value that the customers receive from DG deployment.

Customer Needs

In the traditional regulated market, the electric utility provided a bundled set of services to its customers. These services may be separately provided and priced in a restructured electric industry. The customer needs with respect to electricity are as follows:

- Electric Capacity – the customer needs to have the ability to meet his highest electric load
- Electric Energy – the customer needs electric energy throughout the year according to his particular application needs. For example, a process industry may have a fairly steady consumption of energy around the clock, whereas an office building will have higher needs during the day and also during summer months.
- Power Quality – the customer must operate within a band of voltage and current specifications. Some customers are relatively insensitive to surges or sags in these areas. Other customers require a very "clean" signal.
- Reliability – Customers expect service on demand without interruptions. Outages have negative consequences economically. Some customers have very high outage costs while others do not.
- Cost Certainty – Customers need to be protected from price spikes and other uncontrolled price excursions that have become an unwanted feature of the early competitive power markets.

These needs are the basis for characterizing DG applications and also in determining the competitiveness of equipment in specific applications. In addition to the unbundled electricity services that must be met, the use of DG affects other customer needs

- Noise sensitivity
- Environmental sensitivity
- Space availability
- Weight restrictions.
- Thermal energy needs.

Each customer has a unique set of requirements. These requirements must be met, either by the utility power grid alone, by DG alone, or by a combination of DG and purchased power. **Figure A-4** shows a hypothetical load duration curve. A customer may have a high peaking demand during a small number of hours per year. Often, the power provider will charge such a high charge for this power that it makes sense for the customer to utilize DG for peak shaving. Peak shaving equipment needs to be inexpensive to install. It is not important that it be efficient, that it use a low cost fuel, or that it have a long operating life. In intermediate duty, efficiency and operating costs take on a much greater importance. In addition, the environmental signature of the DG also becomes more important. For equipment that is operating on a continuous basis, efficiency, operating cost, and environmental residuals becomes extremely important. For example, diesel engines are inexpensive to install but expensive to operate and are ideally suited for peaking and standby duty. High capital cost and high efficiency technologies are best suited for baseload applications. The microturbine has some flexibility of design so that products can be optimized for individual market segments.

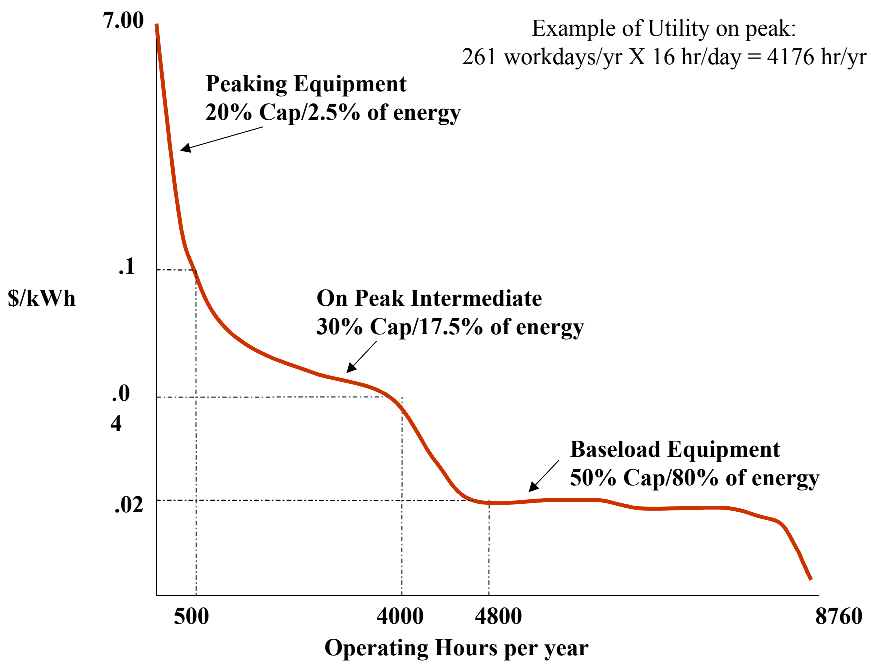


Figure A-4. Customer Load Shape and its Impact on DG Requirements

DG Applications

DG configurations include combined heat and power (CHP), combined cooling, heating and power (CCHP), peak shaving and on-peak systems, standby, other power quality and reliability enhancement, and waste energy utilization.

Combined Heat and Power

High thermal use customers such as process industries, hospitals, health clubs, laundries, etc. can meet their baseload or on peak needs for electricity while meeting their thermal requirements with the waste heat from the DG system. In the smaller size range, fast food, restaurants, health clubs, small hotels and medical facilities have power needs in the 30-250 kW range and steady demand for thermal energy. CHP penetration levels are very high in large process industries, but significant market potential exists in smaller markets. These systems often require complicated financial arrangements and site engineering that add costs particularly for small capacity systems. Heat recovery equipment is required as are grid paralleling and protection functionality. High efficiency and low emissions are important to this market application. CHP also provides social benefits such as lower overall emissions, reduced contribution to global warming, and energy conservation. This market has declined in recent years as customers anticipate lower prices from restructured power markets – an expectation that may be tempered by the recent crisis in California. The long-term outlook is good as new technology becomes available and energy service providers increase marketing effort on this sector.

Standby Power

Standby power systems are required by fire and safety codes hospitals, elevator loads, and water pumping. Standby is an economic choice for customers with high outage costs like telecommunications, retail, process industries. Electric restructuring has resulted in a perception of more frequent outages and vulnerability to price spikes that can be avoided through standby power equipment. This application requires low cost, bare bones installation, with black start (often with a 10 second start-up to load), and grid isolated operation. Efficiency, emissions, and variable maintenance costs are not important. Low-cost diesel generators dominate this market. Competition by microturbines in this segment requires cost reduction to $250-300/kW, possibly in an unrecuperated configuration. However, siting of diesel fuel storage is becoming more difficult leading to more competition by gas-fired equipment especially in the smaller sizes.

Peak Shaving

In many cases, it makes sense for a customer to try to reduce the expensive peak load power. Power during peak periods is expensive both on existing rate schedules, but it is also expensive in competitive hourly power markets. This market is also good for customers with poor load factor, high demand charges, and low thermal loads. Typically, peak shaving does not involve heat recovery, but it may be warranted where the peak period is more than 2,000 hours/year. Generally, equipment first cost is the primary issue. Where peak shaving can be combined with another value such as standby power, the economics are considerably enhanced. Diesel engines may have emissions limitations if their use is to be expanded from simple stand-by to peak shaving.

There are three possible peak shaving strategies. First, the customer can independently optimize his purchased versus generated power compared to his existing rate structure. Under this strategy the unit would operate during the utility-defined peak periods. This creates an operating strategy that can vary, depending on the tariff, from 900 hours/year to as much as 3500 hours/year. Some utilities offer coordinated peak-shaving programs. The utility offers payments for very limited hours of use. These programs typically require as little as 50 hours/year to as many as 400 hours/year. The optimal technology configuration and the need to integrate with standby value differ markedly between these two operating strategies. For customers that purchase power competitively, there is an opportunity to peak shave from the hourly competitive price or to select competitive power supply contracts from energy service providers that are interruptible. In the competitive market peak shaving, the hours of operation would probably be closer to the coordinated utility model than the independent peak shaving of a published tariff.

Transmission and Distribution (T&D) Deferral

DG systems can defer the need for T&D system expansion, thereby reducing costs for both customers and the utility system. There is an emerging requirement for utilities to require up-front payments to serve incremental loads a customer sites. DG systems can be installed to avoid these costs. In addition, utilities can site DG to defer costly substation upgrades.

Grid Isolated Power Systems

Any customer can technically make the choice to utilize DG to isolate from the power grid. However, meeting all of the services that the utility provides (capacity, energy, reserve, reliability, power quality) can be very expensive in terms of equipment needed. Typically, the only time that such an investment is warranted is where the location is in a remote area that either has no access to the grid or where grid access is possible but extremely expensive. Since most grid isolated applications are remote, reliable operation and remote control and dispatch are important values. Often, a system may be remote from fuel sources as well. In this case, PV makes sense. There are some opportunities to utilize small sources of natural gas that are either of low quality or too remote from gathering lines to warrant collection. Onsite power generation may make sense in these cases.

Landfill and Digester Gas Market

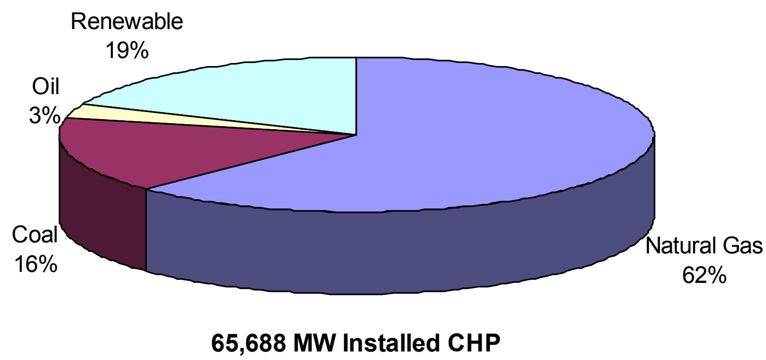
The use of available combustible gaseous fuels from biomass sources at landfills or at sewage treatment plants has been growing at about 15 percent per year. In some areas, the market is enhanced by incentives for DG systems that utilize waste or renewable fuels. Since the fuel is essentially free, high efficiency for the DG system is not a high priority. Fuel quality is an issue as these fuels may have corrosive contaminants, low energy density, and variable characteristics. Management of these fuel characteristics is an important part of a DG system in this application.

Customer Attitudes toward DG

Not only must DG meet customer needs for specific operating strategies as described above, but also customers must be aware of DG and be favorably disposed toward considering DG based solutions. Interest in DG is enhanced by regional differences in energy costs and disruptive events such as restructuring that require everyone to re-evaluate their energy options. Applications that show the most interest in DG tend to be sophisticated customers that utilize professional energy managers, who have historical experience with onsite generating equipment, and who tend to have high energy costs. Commercial customers require more rapid payback for DG investments, perhaps comparing investments to the opportunity costs of other commercial sector investments. Institutional customers, such as universities and government buildings, tend to apply a lower social opportunity cost for their investment acceptance.

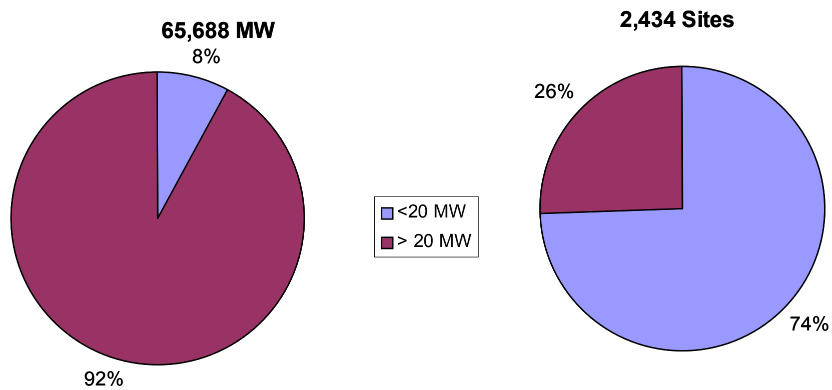
CHP Market History

CHP represents a significant DG market segment. There were over 65,000 MW of CHP capacity installed in the U.S. in 2000[11] **Figure A-5** shows the share by fuel type. Gas-fired CHP is the most common type accounting for nearly two-thirds of total capacity. Not all of this CHP capacity, however, can be characterized as DG. Over 90 percent of total capacity is in large industrial facilities larger than 20 MW as shown in **Figure A-6**. Only, 5,224 MW are in the size range below 20 MW, often defined as DG. This DG capacity does represent 74 percent of the total number of CHP sites.



Source: EEA CHP 2000 Database

Figure A-5. Operating CHP by Fuel Type



Source: EEA CHP 2000 Database

Figure A-6. DG Sized Systems Share of Total CHP Units and Capacity

Figure A-7 shows the distribution of currently operating sites by year of initial operation. In general and especially for DG sized systems, there was a "Golden Age of Cogeneration" from

[11] Based on the *EEA CHP 2000 database*, May 2003

the mid 1980s to the very early 1990s. Number of sites added to the operating list each year went from 25-30 per year in the early 1980s to over 200 per year at the peak of the "Golden Age." Current levels are averaging 75-100 operating sites added per year. The overall market additions have stabilized, though reciprocating engines are taking an increasing share of total additions.

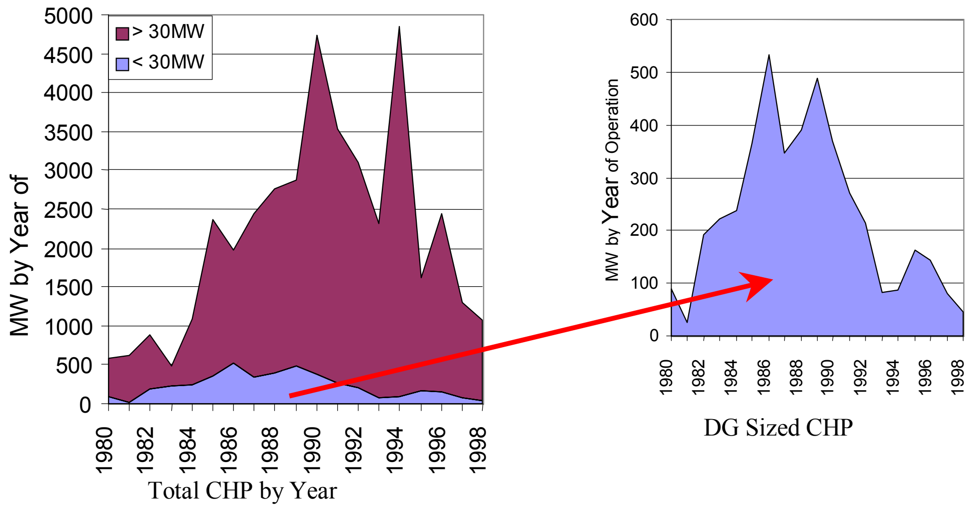


Figure A-7. Total CHP by Year of Installation Compared to DG Sized Systems

A large share of the late 1980s bubble was comprised of small packaged systems with capacities in the 10 to 100 kW size range. Tecogen, ICC, and Goldfire, and North American offered these small packaged systems. **Figure A-8** shows the breakdown of sales for these units. As can be seen in the figure, sales expanded very rapidly from zero to 60-70 units per year in a few years, and then, just as quickly, sales of these units dropped off dramatically. Many of these small packagers are no longer active in the market. Given the similarity in size and performance of this equipment with early market entry microturbine systems, it is important to evaluate what happened to this market.

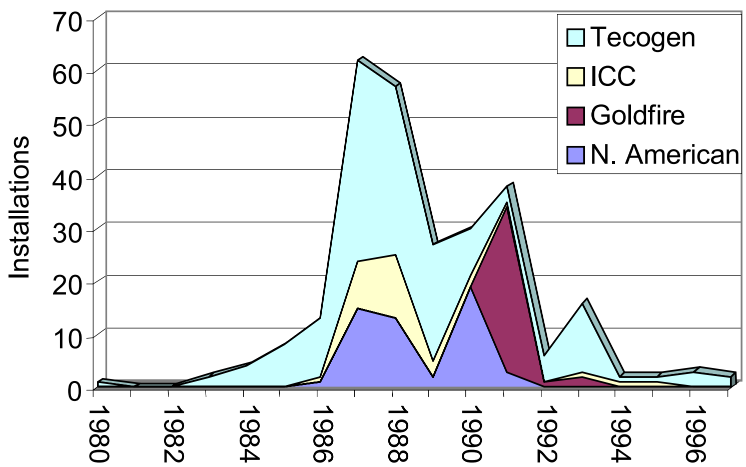


Figure A-8. Growth and Decline of 10-100 kW Packaged CHP Systems

The market for these units declined for the following reasons:

- Small production levels kept unit costs high
- Transaction costs (marketing, design, engineering, permitting, etc.) for these small size units pushed installed costs to 2 or 3 times the bare equipment costs
- Interconnection costs for small units was very expensive
- Maintenance costs were high and life and reliability issues plagued many units
- Withdrawal of utility standard contract offers reduced the benefits to be derived from the systems.

Microturbines are not expected to be plagued by many of these issues. Small capacity paralleling has decreased considerably in cost. Activities are underway to streamline siting and permitting for approved equipment like microturbines. Reliability of the new DG systems is expected to be much higher than the systems offered in the 1980s. However, the issue of high transaction costs for small systems is one that needs to be carefully addressed in order to keep installed costs in a competitive range.

APPENDIX B – EXISTING CHP

The industrial sectors that have installed combined heating and cooling (CHP) systems are obvious candidates for growing the CHP market with the AMTS. **Table B-1** summarizes the existing applications of combined heat and power (CHP) in the industrial sector, including agricultural and construction (SIC codes 1-39). The table identifies those sites less than 2 MW in size that would be appropriate for the Capstone AMTS. The largest number of applications is in the food industry, high value chemicals, lumber and wood products, and a variety of fabricating processes. Other important uses are paper, oil and gas extraction, and agriculture, particularly high value and greenhouse culture. A detailed breakdown of industrial applications by 4-digit SIC is provided in **Table B-2.** This information was used in part to develop a list of SIC codes for assessing the CHP value propositions[12].

Table B-1. Summary of Small Existing CHP in the Industrial Sector

Category	Active Sites <2 MW	Description
Food and Kindred Products	54	Wide range of food industries, especially dairy, canning, frozen fruits and vegetables
Chemicals and Allied Products	30	Higher value, small production chemicals
Lumber and Wood Products	24	Many applications within the industry
Fabricated Metal Products	23	Tools, stampings, electroplating, and other small parts
Paper and Allied Products	19	Variety of paper and paperboard applications
Oil and Gas Extraction	18	Oil and gas field applications
Misc. Manf. Industries	17	Not defined by use
Agricultural Production -Crops	11	High value agricultural products and greenhouse operations
Industrial Machinery and Equipment	11	Widespread
Primary Metal Industries	8	Small production operations
Other	51	Furniture, refining, clay products, textile mills, plastics, product fabrication industries
Total	266	

[12] CHP data based on EEA CHP 2000 database

Table B-2. Small Existing CHP in the Industrial Sector

SIC *	Application Description	Size Range MW** 0-1	1-2	Sites
161	Vegetables and Melons	1		1
174	Citrus Fruits	1		1
181	Ornamental Floriculture and Nursery Products	2		2
182	Food Crops Grown Under Cover	3	1	4
1	Agricultural Production -- Crops	3		3
	1 Total	10	1	11
1311	Crude Petroleum and Natural Gas	14	4	18
	13 Total	14	4	18
2013	Sausages and Other Prepared Meats	1		1
2015	Poultry Slaughtering and Processing	1		1
2021	Creamery Butter	2	1	3
2022	Natural, Processed, and Imitation Cheese	1		1
2026	Fluid Milk	6	1	7
2033	Canned Fruits, Veg., Preserves, Jams, Jellies	2		2
2037	Frozen Fruits, Fruit Juices, and Vegetables	1		1
2041	Grain	2		2
2044	Rice Milling	1		1
2051	Bread and Other Bakery Products	2	5	7
2061	Cane Sugar, Except Refining	1	1	2
2062	Cane Sugar Refining	1	2	3
2063	Beet Sugar		1	1
2066	Chocolate and Cocoa Products		1	1
2068	Salted and Roasted Nuts and Seeds	1		1
2075	Soybean Oil Mills		2	2
2084	Wines, Brandy, and Brandy Spirits	1		1
2086	Bottled and Canned Soft Drinks and Carbonated Waters	2	2	4
2091	Canned and Cured Fish and Seafood	2	1	3
2099	Food Preparations, NEC	2		2
20	Food and Kindred Products	7	1	8
	20 Total	36	18	54

* 4-digit SIC codes where available in the data, if two digit SIC is listed, there was no 4-digit classification for those sites.
** Total capacity at the site, may include multiple prime movers

Table B-2. Small Existing CHP in the Industrial Sector (continued)

SIC*	Application Description	Size Range MW** 0-1	1-2	Sites
21	Tobacco Manufacturers		2	2
	21 Total		2	2
22	Textile Mill Products	3	3	6
	22 Total	3	3	6
2411	Logging		2	2
2421	Sawmills and Planing Mills, General	12	3	15
2426	Hardwood Dimension and Flooring Mills	1		1
2436	Softwood Veneer and Plywood	1		1
2491	Wood Preserving	2		2
24	Lumber and Wood Products	2	1	3
	24 Total	18	6	24
2511	Wood Household Furniture, Except Upholstered	6	1	7
2512	Wood Household Furniture, Upholstered	2		2
	25 Total	8	1	9
2621	Paper Mills	7	3	10
2631	Paperboard Mills	1	6	7
2679	Other Paper	1	1	2
	26 Total	9	10	19
2711	Newspapers, Publishing, Printing		1	1
2732	Book Printing	1		1
	27 Total	1	1	2
2810	Basic Chemicals		1	1
2813	Industrial Gases	1		1
2819	Industrial Inorganic Chemicals, NEC	1		1
2821	Plastics Material and Synthetic Resins, and Nonvulcanizable Elastomers	2		2
2834	Pharmaceutical Preparations	1	3	4
2841	Soaps and Other Detergents	1	1	2
2869	Industrial Organic Chemicals, NEC	1		1
2891	Adhesives and Sealants	1		1
2899	Chemicals and Chemical Preparations, NEC		4	4
28	Chemicals and Allied Products	10	3	13
	28 Total	18	12	30
29	Petroleum and Coal Products	1	6	7
	29 Total	1	6	7

* 4-digit SIC codes where available in the data, if two digit SIC is listed, there was no 4-digit classification for those sites.
** Total capacity at the site, may include multiple prime movers

Table B-2. Small Existing CHP in the Industrial Sector (continued)

SIC*	Application Description	Size Range MW** 0-1	1-2	Sites
3021	Rubber and Plastics Footwear	1		1
3061	Molded, Extruded, and Lathe-Cut Mechanical Rubber Goods	1		1
3069	Fabricated Rubber Products, NEC	1	1	2
3086	Plastics Foam Products	1		1
	30 Total	4	1	5
3241	Cement, Hydraulice	1		1
3251	Brick and Structural Clay Tile	2	1	3
3275	Gypsum Products		1	1
3295	Minerals and Earths, Ground or Otherwise Treated		1	1
32	Stone, Clay, Glass and Concrete Products	1		1
	32 Total	4	3	7
3312	Steel Works, Blast Furnaces (Including Coke Ovens), and Rolling Mills	3		3
3322	Malleable Iron Foundries	1		1
3357	Drawing and Insulating of Nonferrous Wire	1		1
33	Primary Metal Industries	3		3
	33 Total	8		8
3423	Hand and Edge Tools, Except Machine Tools and Handsaws		1	1
3469	Metal Stamping, NEC	1		1
3471	Electroplating, Plating, Polishing, Anodizing, and Coloring	13		13
3499	Valves and Pipe Fittings, NEC		1	1
34	Fabricated Metal Products	7		7
	34 Total	21	2	23
3519	Internal Combustion Engines, NEC	1	1	2
3545	Cutting Tools, Machine Tool Accessories, and Machinists' Precision Measuring Devices	1		1
3569	General Industrial Machinery and Equipment, NEC	2		2
35	Industrial Machinery and Equipment	6		6
	35 Total	10	1	11
3613	Switchgear and Switchboard Apparatus	1		1
3639	Household Appliances, NEC	1		1
36	Electrical and Electronic Equipment		2	2
	36 Total	2	2	4

* 4-digit SIC codes where available in the data, if two digit SIC is listed, there was no 4-digit classification for those sites.

** Total capacity at the site, may include multiple prime movers

Table B-2. Small Existing CHP in the Industrial Sector (continued)

SIC*	Application Description	Size Range MW** 0-1	1-2	Sites
3731	Ship Building and Repairing	1	1	2
37	Transportation Equipment	2		2
	37 Total	3	1	4
3841	Surgical and Medical Instruments and Apparatus	1		1
38	Instruments and Related Products	1		1
	38 Total	2		2
39	Misc. Manf. Industries	13	4	17
	39 Total	13	4	17
	Grand Total Agricultural and Manufacturing	187	79	266

* 4-digit SIC codes where available in the data, if two digit SIC is listed, there was no 4-digit classification for those sites.
** Total capacity at the site, may include multiple prime movers

Table B-3 summarizes the primary CHP markets in the commercial and institutional sector. There are a large number of applications in health services, secondary schools, apartment buildings, health clubs, laundries, and hotels. There has also been some penetration of CHP in restaurants, office buildings (private and government), and prisons. A detailed breakdown of commercial applications by 4-digit SIC is provided in **Table B-4.**

Table B-3. Summary of Small Existing CHP in the Commercial Sector

Category	Active Sites <2 MW	Description
Health Services	169	Smaller general hospitals, nursing homes, and specialty clinics
Educational Services	156	Secondary schools and some smaller colleges and technical schools
Real Estate	123	Mostly apartment buildings with some nonresidential buildings included
Hotels, Rooming Houses, etc.	82	Small hotels and motels
Personal Services	77	Power laundries, coin-op laundries, linen supply, industrial laundries
Amusement and Recreational Services	76	Health clubs, sport clubs, water parks
Private Households	34	Use not defined
Electric, Gas, and Sanitary Services	31	Natural gas, water, sewer, and refuse
Eating and Drinking Places	13	Full service and fast food restaurants
Exec., Leg., and General Government	13	Use not defined, probably office buildings
Food Stores	11	Grocery stores
Social Services	10	Use not defined, probably office buildings
Miscellaneous Services	10	Use not defined
Justice, Public Order, and Safety	9	Courthouses and prisons
Other	62	Retail and wholesale trade, warehouses, offices, automotive dealers, transportation and arboreta (probably greenhouse)
C&I Total	876	

Table B-4. Small Existing CHP in the Commercial Sector

SIC*	Application Description	Size Range MW** 0-1	1-2	Sites
4212	Local Trucking without Storage	1		1
4222	Warehousing		1	1
4226	Special Warehousing and Storage, NEC	1		1
	42 Total	2	1	3
4512	Air Transportation Scheduled	1		1
4513	Air Courier Service	1		1
4581	Airports, Flying Fields, and Airport Terminal Services	2		2
	45 Total	4		4
4833	Television Broadcasting Stations		1	1
	48 Total		1	1
4924	Natural Gas Distribution	3		3
4939	Combination Utilities		2	2
4941	Water Supply	1	1	2
4952	Sewerage Systems	8	6	14
4953	Refuse Systems	4	5	9
4961	Steam and Air-Conditioning Supply		1	1
	49 Total	16	15	31
5012	Automobiles and Other Motor Vehicles	1		1
5063	Electrical Apparatus and Equipment Wiring Supplies, and Construction Materials	1		1
	50 Total	2		2
5113	Industrial and Personal Service Paper	1		1
5149	Groceries and Related Products, NEC	1		1
5172	Petroleum and Petroleum Products Wholesalers, Except Bulk Stations and Terminals	2		2
5193	Flowers, Nursery Stock, and Florists' Supplies	1		1
	51 Total	5		5

* 4-digit SIC codes where available in the data, if two digit SIC is listed, there was no 4-digit classification for those sites.
** Total capacity at the site, may include multiple prime movers

Table B-4. Small Existing CHP in the Commercial Sector (continued)

SIC*	Application Description	Size Range MW** 0-1	1-2	Sites
5311	Department Stores	4		4
	53 Total	4		4
5411	Grocery Stores	11		11
	54 Total	11		11
5531	Auto and Home Supply Stores	1		1
5541	Gasoline Service Stations	1		1
	55 Total	2		2
5812	Eating and Drinking Places	13		13
	58 Total	13		13
6035	Savings Institutions		2	2
	60 Total		2	2
6512	Operators of Nonresidential Buildings	24	2	26
6513	Operators of Apartment Buildings	94	1	95
	65 Total	118	3	121
7011	Hotels and Motels	79	3	82
	70 Total	79	3	82
7211	Power Laundries, Family and Commercial	32		32
7213	Linen Supply	6		6
7215	Coin-Operated Laundries and Drycleaning	39		39
	72 Total	77		77
7542	Carwashes	3		3
	75 Total	3		3

* 4-digit SIC codes where available in the data, if two digit SIC is listed, there was no 4-digit classification for those sites.
** Total capacity at the site, may include multiple prime movers

Table B-4. Small Existing CHP in the Commercial Sector (continued)

SIC*	Application Description	Size Range MW** 0-1	1-2	Sites
7991	Physical Fitness Facilities	32		32
7996	Amusement Parks		1	1
7997	Membership Sports and Recreation Clubs	32		32
7999	Amusement and Recreation Services, NEC	10	1	11
	79 Total	74	2	76
8011	Offices and Clinics of Doctors of Medicine	2		2
8051	Skilled Nursing Care Facilities	71		71
8052	Intermediate Care Facilities	2		2
8062	General Medical and Surgical Hospitals	59	25	84
8069	Specialty Hospitals, Except Psychiatric	5	2	7
80	Health Services	3		3
	80 Total	142	27	169
8211	Elementary and Secondary Schools	100	3	103
8221	Colleges, Universities, and Professional Schools	31	8	39
8222	Junior Colleges and Technical Institutes	8		8
8249	Vocational Schools, NEC		1	1
8299	Schools and Educational Services, NEC	1	1	2
82	Educational Services		3	3
	82 Total	140	16	156
8322	Individual and Family Social Services	8		8
83	Social Services	2		2
	83 Total	10		10
8422	Arboreta and Botanical or Zoological Gardens	1		1
	84 Total	1		1
8661	Religious Organizations	3		3
	86 Total	3		3

* 4-digit SIC codes where available in the data, if two digit SIC is listed, there was no 4-digit classification for those sites.
** Total capacity at the site, may include multiple prime movers

Table B-4. Small Existing CHP in the Commercial Sector (continued)

SIC*	Application Description	Size Range MW**		Sites
		0-1	1-2	
8731	Commercial Physical and Biological Research		3	3
	87 Total		3	3
8811	Private Households	34		34
	88 Total	34		34
89	Miscellaneous Services	10		10
	89 Total	10		10
9111	Executive Offices (gov't.)	10	1	11
9199	General Government, NEC	2		2
	91 Total	12	1	13
9211	Courts	3		3
9223	Correctional Institutions	3	2	5
92	Justice, Public Order, and Safety		1	1
	92 Total	6	3	9
9511	Air and Water Resource and Solid Waste Management	1	1	2
	95 Total	1	1	2
9711	National Security	26	3	29
	97 Total	26	3	29
	Commercial and Industrial CHP Total	795	81	876

* 4-digit SIC codes where available in the data, if two digit SIC is listed, there was no 4-digit classification for those sites.
** Total capacity at the site, may include multiple prime movers