Final Report

Cooling, Heating, and Power for Industry: A Market Assessment

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COOLING, HEATING AND POWER FOR INDUSTRY:
A MARKET ASSESSMENT

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EXECUTIVE SUMMARY

Combined heat and power (CHP) has the potential to dramatically reduce industrial sector carbon and air pollutant emissions and increase source energy efficiency. Industrial applications of CHP have been around for decades, producing electricity and byproduct thermal energy onsite, and converting 80 percent or more of the input fuel into useable energy. Typically, CHP systems operate by generating hot water or steam from the recovered waste heat and using it for process heating, but it also can be directed to an absorption chiller where it can provide process or space cooling. These applications are also known as cooling, heating, and power.

The focus of this study was to assess the market for cooling, heating, and power applications in the industrial sector. New thermally-driven cooling technologies are being developed and demonstrated that can potentially utilize the CHP heat output effectively for uses typically reserved for high-value electricity. CHP with cooling has potential applications that could not be economically served by CHP alone, creating an additional use of the byproduct thermal energy when heating loads are minimal. Now more than ever, CHP can potentially decrease carbon and air pollutant emissions while improving energy efficiency in the industrial sector.

In today's marketplace, there are a variety of cooling technology options for cooling, heating, and power. Absorption chillers are available that can be installed with a CHP system to utilize the heat output to produce process cooling. For the purpose of this study, engine-driven chillers are considered cooling, heating and power applications since they provide thermal output, in the form of process or space cooling, and also displace electricity that typically would be purchased to provide this cooling. Desiccant technology, which can be used in conjunction with CHP waste heat to provide cooling, has not been considered due to deficiencies in energy use data but would add to the market potential estimated in this effort.

The focus of this study was on smaller CHP technologies, otherwise known as distributed generation (DG). DG is defined here as power generation smaller than 50 MW with the unit output being used either on-site or close to where it is produced. Other potential uses of DG technologies include peak shaving, premium power, and "green" power. However, given the study objective of assessing the most likely markets for CHP technology, the focus of this study was on cooling, heating and power applications, with straight power generation (i.e. without heat recovery) also included.

To determine the potential for cooling, heating and power in the U.S. industrial sector, this effort evaluated a wide range of DG units. The study focused on units due for production by year 2002 (base case scenario), and includes reciprocating engines, industrial turbines, microturbines, combined-cycle turbines, and phosphoric acid fuel cells. Table ES-1 summarizes the scope of this effort. A future case is included as a sensitivity and considers significant improvements in cost and performance for each of these technologies, as well as the emergence of solid oxide fuel cells.

Table ES-1. Summary of Study Scope

	Size (MW)	Applications	Technologies
Included	Up to 50 MW	Combined heat and power (CHP) Cooling, heating and power Straight power generation (no heat recovery)	Reciprocating engines Microturbines Industrial turbines Combined cycle turbines Fuel cells Absorption chillers
Not included	Greater than 50 MW	Peak shaving Backup/emergency power "Green" power	Renewables Desiccants

Market Potential and Market Penetration

The market potential was estimated for cooling, heating and power applications, including power generation without heat recovery, straight CHP, CHP with absorption cooling, and engine-driven chillers (EDC) for process cooling. As shown in Figure ES-1, the potential for these applications in the U.S. industrial sector is estimated at 33 GW of power generating capacity with currently available technology.

In Figure ES-1, market estimates show that almost three-quarters (about 24 GW) of the current potential is for straight CHP applications, where the waste heat from power generation is used for process heating. CHP with an absorber represents 15 percent of the potential (about 5 GW), serving industries with substantial cooling demand, including the chemical and petroleum industries.

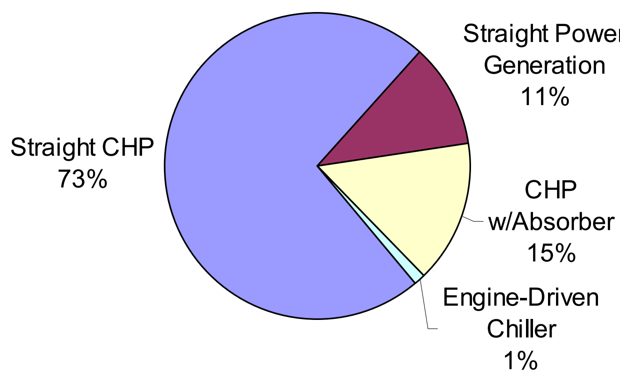

Figure ES-1. U. S. Industrial Cooling, Heating and Power Market Potential (33 GW)

There is still a market for straight power generation, without recovering the waste heat, mostly for larger industrials that can accommodate larger (20-50 MW) combined cycle units that offer low cost of generation. These applications are strong in California, with its high grid prices, as well as with large primary metals facilities with limited steam/hot water demands. There is little potential for engine-driven chillers based on their power generating capacity, but they represent over a third of the CHP cooling capacity on a tonnage basis in this analysis (see Figure ES-5 for more detail). The details of the analysis provide some insight into this market breakdown when aspects such as the type of technology, regional characteristics, and industry needs are considered.

Based on data from the Energy Information Administration (EIA), it is estimated that current CHP use in the industrial sector for units under 50 MW is about 11 GW[1]. Comparing this value with the market potential estimate of 33 GW, it would appear that the market penetration is about one-third. While there is little data on penetration rates of new CHP technology under current economic conditions, the commercial and industrial decision-making process regarding energy-related investments in general can yield some insights.

Many studies on the acceptance of energy-saving investments examine the amount of time necessary to payback the investment. While the market potential presented here is based on a ten-year cash flow analysis to determine the option with the best net present value, a simple payback was also calculated. Figure ES-2 illustrates for the current case that almost 20 percent of the applications offer a payback under 2 years, and almost 60 percent (about 20 GW) of the applications deemed economically feasible have a payback under 4 years. Assuming that the 11 GW that has been installed was taken from the more attractive paybacks, that means that about 9 GW of under 4 year payback market potential is still unrealized. This portion is likely impeded by market or regulatory barriers discussed in Section 4 of this report.

A general rule of thumb is that a 2-4 year payback is required for industrial facilities to purchase equipment that will reduce their energy bill. With 9 GW of applications offering paybacks in this range that have not been installed, the indication is that further cost reductions or economic assistance (e.g. tax incentives or rebates) may be required to stimulate this attractive but unrealized portion of the market.

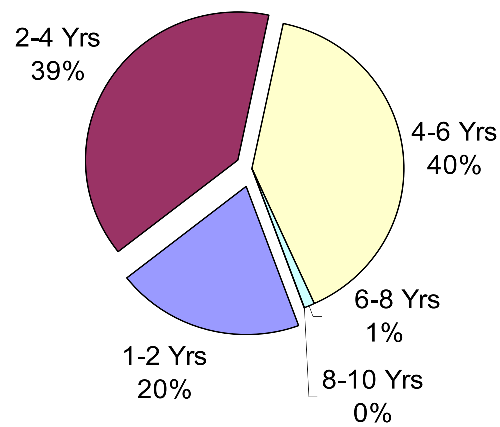

Figure ES-2. Distribution of Payback Periods for Potential Industrial CHP Applications (33 GW)

Market Potential by Technology and Size Range

Figure ES-3 illustrates the projected market potential by CHP technology. The market analysis shows that in the base case, the CHP marketplace is shared by turbines and reciprocating engines.

In the future, turbines are projected to adopt many of the high efficiency features pioneered by the Department of Energy (DOE) Advanced Turbine Systems (ATS) Program, and thus take CHP market share from ATS, combined cycle systems, and even improved reciprocating engines. The reason for the turbines capturing future market potential is that the electrical efficiency improvements projected for turbines are much greater (relative to their current efficiency) than those projected for reciprocating engines,

[1] Energy Information Administration, Form 860B, 1999.

while turbines continue to hold an advantage in terms of quality of thermal output.

In the future scenario, overall market potential improves as well, almost reaching 50 GW (from 33 GW). Although not shown on the figure, in the future fuel cells are projected to drop below $1,500/kW installed with the development of molten carbonate and solid oxide technologies, and emerge in the future CHP marketplace with less than 5 MW of capacity. This penetration could continue if further improvements in fuel cell cost (i.e. below $1,500/kW) are attained.

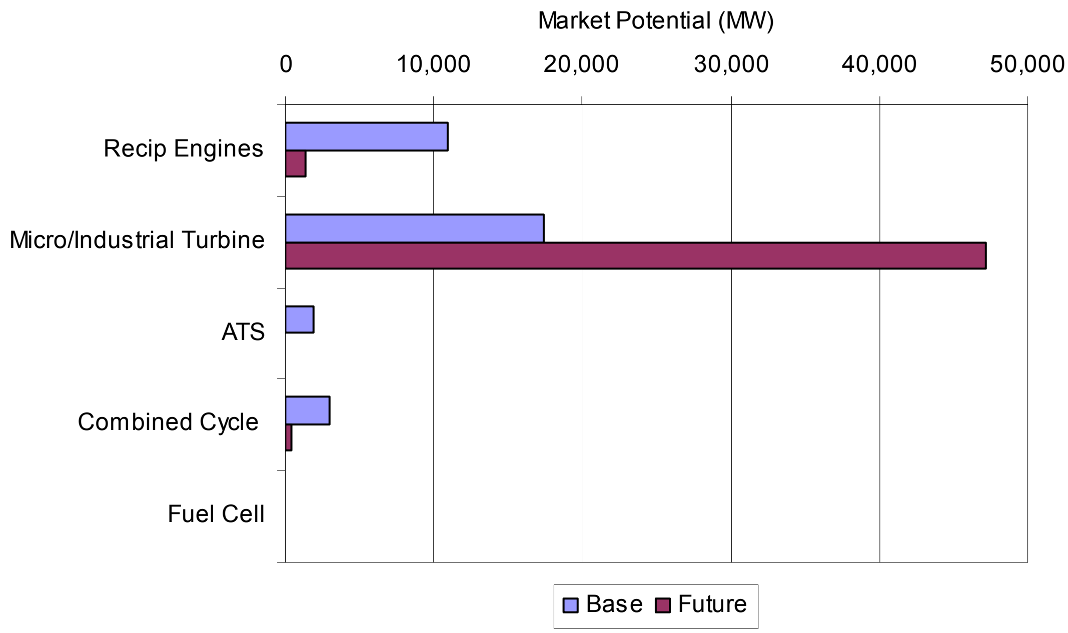

Figure ES-3. Market Potential by Technology (MW)

Figure ES-4 shows how the market potential of CHP technologies varies by the size of the generating unit. In the base case, engines dominate in the smaller sizes (under 1 MW) over microturbines and fuel cells. Their combination of high efficiencies and competitive installed cost makes them hard to beat. In the mid range (1-20 MW), turbines take over, due to the large concentration of CHP compatible sites in this size range. Turbines offer better economics for CHP when most or all of the thermal output is valued. In the larger sizes (20-50 MW), turbines do well in CHP applications and combined cycles emerge, offering economic potential for baseload power applications. The combined cycle applications are attractive in industries (such as steel) with relatively low steam demands and for larger plants in states with high retail rates, such as California.

In the future, the turbine CHP market potential greatly expands as microturbines take over in the under 1 MW applications, and larger (over 1 MW) turbines benefit from improved electrical efficiency and lower capital cost per unit power output. Again, many of these improvements are seen as resulting from the ATS program for over 1 MW turbines, and similar improvements in microturbines and engines are expected to result from DOE's Advanced Microturbine and Advanced Reciprocating Engine Systems (ARES) programs.

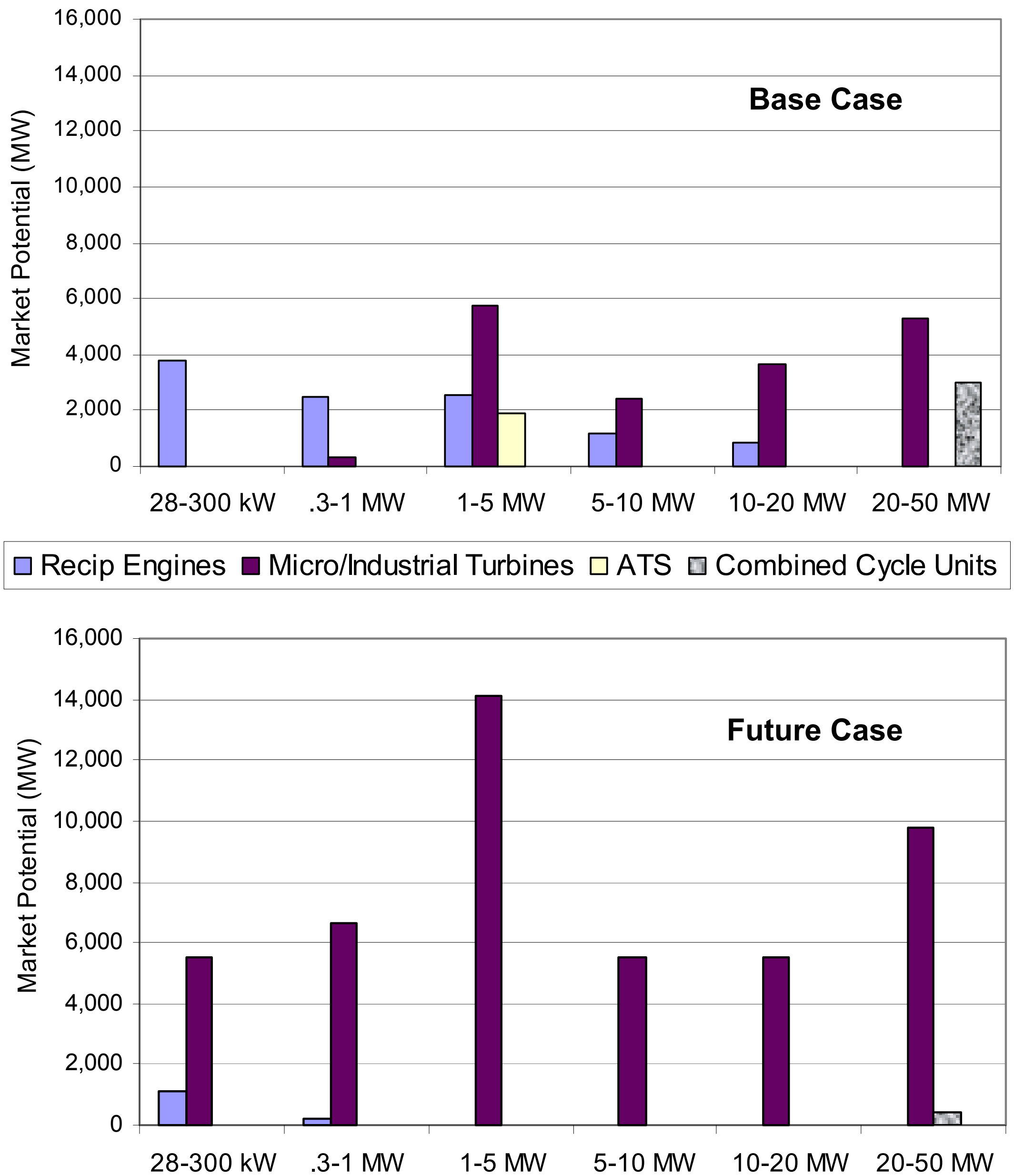

Figure ES-4. CHP Technology Market Potential by Unit Size

Furthermore, as previously shown in Figure ES-1, about 16 percent of the potential applications of CHP favored the generation of cooling from the CHP unit. Four different cooling operating strategies were explored, including single effect absorption units and engine-driven chillers, both baseloaded and serving the entire cooling load. The market potential, in terms of cooling tons, is shown in Figure ES-5 for each of these four strategies.

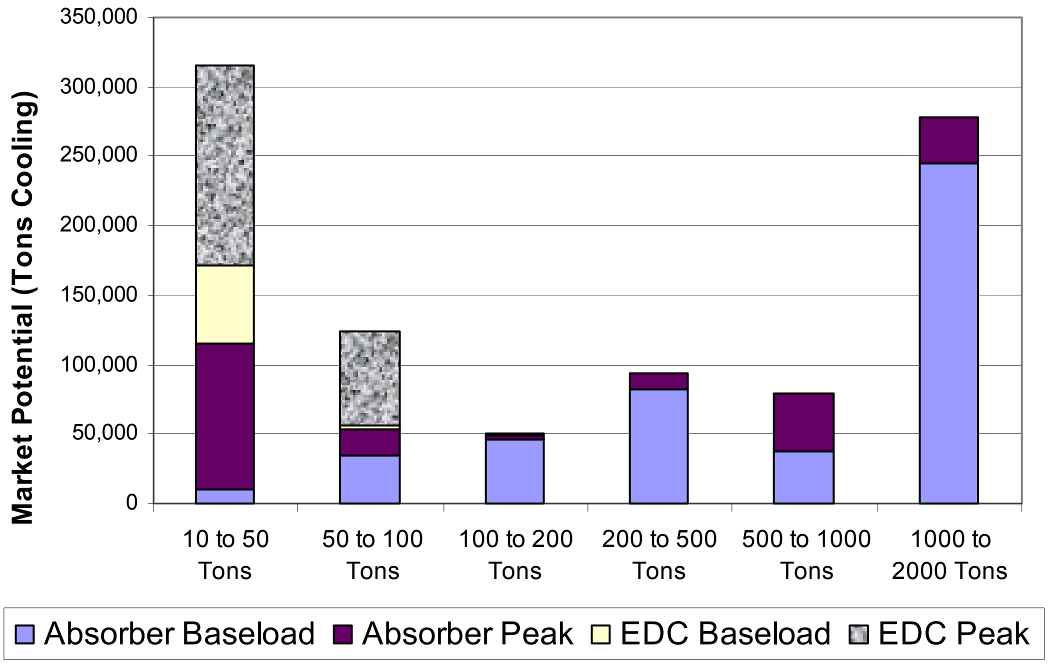

Figure ES-5. CHP Cooling Market Potential by Range of Cooling Unit Size

Figure ES-5 shows that Engine-Driven Chillers (EDCs) are competitive in the smaller size ranges, particularly for serving the entire cooling load (sized to peak). In the 10-50 ton range, EDCs sized to peak offer the potential for over 140,000 tons of cooling. Peak-sized absorbers also do well in this smaller range, representing over 100,000 tons of potential cooling. A similar but lower potential is demonstrated in the 50-100 ton range, and as the on-site cooling load grows, the potential for baseload absorbers takes hold. This technology and operating strategy leads the remainder of the cooling size ranges, topped off by the 1,000-2,000 ton range, where baseload absorbers show most of their potential. In this size, the capital cost of absorbers drops significantly, and the economics improve as a result.

Four scenarios were constructed to evaluate how sensitive the base case is to varying inputs. In the first scenarios (the Future Case), the focus was on how improvements in CHP cost and/or efficiency impact potential market size. The remaining three sensitivities were added to illustrate the effects of changing natural gas prices on the CHP market for industrial applications, including the accompanying effect on retail electric prices. Of these, a high price scenario (High) reflected a jump in gas prices that remained high throughout the life of the DER unit, whereas the moderate price scenario (Moderate) reflected a temporary jump followed by a return to lower prices. In both of these cases, retail electricity prices (the energy component) were adjusted upward to reflect the impact of the higher gas prices on wholesale electric prices, using a methodology similar to how utilities calculate their fuel adjustment clauses. The Peak scenario uses the high gas price scenario, but reflects the gas price impact on the demand component of the retail electricity prices. Appendix A provides more detail on these scenarios.

Overall market potential results of the sensitivity analysis (see Figure ES-6) indicate that improvements in installed cost and efficiency increase the potential market size dramatically. The Future Case (reflecting improved CHP cost and performance) increases the potential market from 33 to almost 50 GW, a 50 percent increase in the market size. The impact of increasing natural gas prices is shown in the Moderate, High, and Peak scenarios as decreasing the market potential for industrial CHP, even with accompanying increases in electric prices. As shown in Section 3 of the report, the decrease in market potential was lower in regions where concentrations of natural gas generation exist in the wholesale electric market, including West South Central, Pacific, and parts of the Northeast and Mid-Atlantic. This effect will likely diminish somewhat as more gas-fired generation is placed in service in these regions to meet future capacity needs.

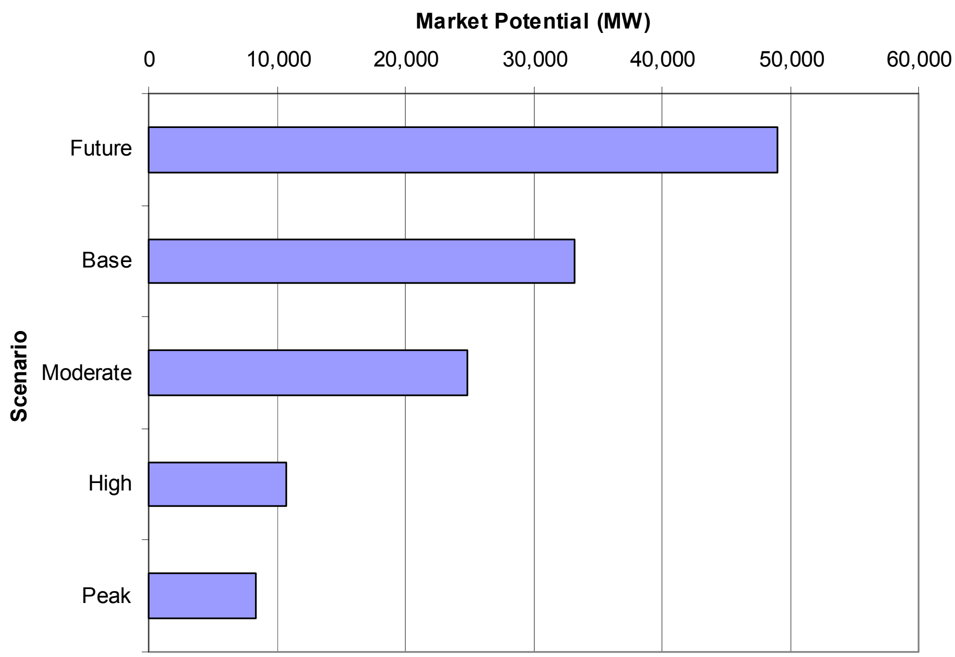

Figure ES-6. Future Scenario Offers Highest Market Potential

Despite improving economics, increasing emphasis on overall energy efficiency, and concerns over restructuring of the electric utility industry, CHP systems face challenges for further penetration in the industrial market. The realization of benefits inherent in implementing CHP on a wide scale is hindered by a combination of barriers in the following categories:

- Economics and Tax Treatment
- Product Performance and Availability
- Awareness, Information and Education
- Utility Policies and Regulation
- Planning, Zoning and Codes
- Environmental Regulation
- Supporting Market Infrastructure

These barriers can often make a CHP project uneconomic, and can frequently present a confused and uncertain option to potential end users.

To overcome these barriers and maximize the many benefits of industrial CHP, further R&D is needed to allow these technologies to compete with more conventional options. CHP and thermal cooling technologies share the need for lower costs, increased efficiency, reduced maintenance, greater reliability, and lower emissions. While these needs vary by technology, the overall goal should be to support industry in developing lower cost CHP packages that improve industrial energy efficiency and reduce operating costs. These technologies should cover a wide range of sizes and options to fit the needs of the many different industrial sectors.

Section 1
INTRODUCTION

Combined heat and power (CHP) has the potential to dramatically reduce industrial sector carbon and air pollutant emissions and increase source energy efficiency. Industrial applications of CHP have been around for decades, producing electricity and byproduct thermal energy onsite, and converting 80 percent or more of the input fuel into useable energy. Typically, CHP systems operate by generating hot water or steam from the recovered waste heat and using it for process heating, but it also can be directed to an absorption chiller where it can provide process or space cooling. These applications are also known as cooling, heating, and power.

The focus of this study was to assess the market for cooling, heating, and power applications in the industrial sector. New thermally-driven cooling technologies are being developed and demonstrated that can potentially utilize the CHP heat output effectively for uses typically reserved for high-value electricity. CHP with cooling has potential applications that could not be economically served by CHP alone, creating an additional use of the byproduct thermal energy when heating loads are minimal. Now more than ever, CHP can potentially decrease carbon and air pollutant emissions while improving energy efficiency in the industrial sector.

In today's marketplace, there are a variety of technology options for CHP with cooling. Absorption chillers are available that can be installed with a CHP system to utilize the heat output to produce process cooling. Engine-driven chillers produce cooling and displace electricity typically purchased to provide cooling, and thus are also treated as CHP systems for the purpose of this study. Desiccant technology, which can be used in conjunction with CHP waste heat to provide cooling, has not been considered due to deficiencies in energy use data but would add to the market potential estimated in this effort.

The focus of this study was on smaller CHP technologies, otherwise known as distributed generation (DG). DG is defined here as power generation smaller than 50 MW with the unit output being used either on-site or close to where it is produced. Other potential uses of DG technologies include peak shaving, premium power, and "green" power. However, given the study objective of assessing the most likely markets for CHP technology, the focus of this study was on cooling, heating and power applications, with straight power generation (i.e. without heat recovery) also included.

To determine the potential for cooling, heating and power in the U.S. industrial sector, this effort evaluated a wide range of DG units up to 50 MW in size. The study focused on units due for production by year 2002 (base case scenario), and includes reciprocating engines, industrial turbines, microturbines, combined-cycle turbines, and phosphoric acid fuel cells. Table 1-1 summarizes the scope of this effort. A future case is included as a sensitivity that considers significant improvements in cost and performance for each of these technologies, as well as the emergence of solid oxide fuel cells.

Table 1-1. Summary of Study Scope

	Size (MW)	Applications	Technologies
Included	Up to 50 MW	Combined heat and power (CHP) Cooling, heating and power Straight power generation (no heat recovery)	Reciprocating engines Microturbines Industrial turbines Combined cycle turbines Fuel cells Absorption chillers
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DOE Objectives

DOE's focus on CHP for industry is part of a broader initiative aimed at increasing the use of CHP. At the CHP Summit in December of 1998, DOE announced a national goal of doubling CHP capacity by 2010. Since then, the DOE Office of Energy Efficiency and Renewable Energy (EERE) issued a CHP Challenge to achieve this goal. With published levels of CHP at about 46 GW in 1998, this goal means adding about 46 GW by 2010, bringing the installed CHP base to 92 GW by that time.

The overwhelming majority of CHP systems currently installed in the U.S. are used for industrial applications, with increasing usage by commercial and institutional building owners and district energy systems worldwide. The CHP Initiative, coordinated by the Office of Distributed Energy Resources, seeks to raise awareness of the energy, economic and environmental benefits of CHP and to highlight barriers that limit its increased implementation. The Initiative supports a range of activities including regional, national, and international meetings, industry dialogues, and development of educational materials.

This study supports the CHP Initiative by assessing technologies and markets where CHP is positioned for growth and identify the barriers that impede growth. It should be noted that DOE has published a number of other reports that explore such barriers in more detail. In this effort, however, the focus is on areas where technology needs improvement to expand the market potential, and what the potential market effects of such improvements would be.

To satisfy these objectives, this study was intended to:

- Summarize the current state-of-the-art in cooling technologies that can be employed in the industrial sector within a CHP system, including absorption and engine-driven units,
- Quantify the industrial market for CHP, focusing on units up to 50 MW, and model the effects of improving the cost and performance of these units,
- Identify key market drivers and barriers, and

- Explore potential areas for technology research and development that could improve the prospects for CHP in industry.

While this effort focuses on the industrial sector, there is a companion study that examined the potential for CHP in buildings, and their ability to provide significant contributions to the CHP Challenge goal. This study, entitled *Integrated Energy Systems (IES) for Buildings: A Market Assessment*, was also developed for ORNL and DOE by the Resource Dynamics Corporation. It was published August 2002 and can be found on the web at http://www.bchp.org/pdfs/IES_Resource_Dynamics-FinalReport-0209.pdf.

Section 2

CHP TECHNOLOGY STATE-OF-THE-ART

A number of advances in electricity generating technologies are becoming available that will enable these technologies to provide electric and thermal energy in an efficient, clean, and cost-effective manner. Combined with electric utility industry restructuring, these technology advancements will challenge the ways that facilities meet demands for electricity and thermal energy. This section reviews the current status of these technologies, and examines key developments that are needed to improve their cost and performance.

Reciprocating Engines

Of the CHP technologies, reciprocating engines were developed first (more than 100 years ago) and have long been used for electricity generation. Both Otto (spark ignition) and Diesel Cycle (compression ignition) engines have gained widespread acceptance in almost every sector of the economy, and are used for applications ranging from fractional horsepower units for small hand-held tools to enormous 60 MW baseload electric power plants. Reciprocating engines in the >1 MW size range are primarily designed for power generation, marine, and direct drive applications.

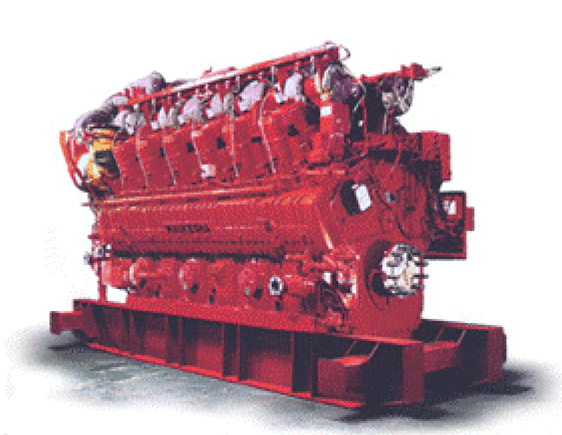


Figure 2-1. Waukesha ATGL (1.2 – 2.5 MW) Series Natural Gas Engine

Most engines used for power generation are four-stroke and operate in four cycles (intake, compression, combustion, and exhaust). The four-stroke process begins with fuel and air being mixed, usually before introduction into the combustion cylinder for spark ignited units (see Figure 2-2). In turbocharged applications, the air is compressed before mixing with fuel. The fuel/air mixture is introduced into a combustion cylinder that is closed at one end and contains a moveable piston. The mixture is then compressed as the piston moves toward the top of the cylinder. For diesel units, the air and fuel are introduced separately with fuel injected after the air is compressed. When the piston nears the top of its stroke (timing is either optimized for the most efficient power generation or to reduce emissions), a spark is produced igniting the mixture (in a non-spark ignited diesel engine, the mixture is ignited by the compression alone). The pressure of the hot, combusted gases drives the piston down the cylinder. Energy in the moving piston is translated to rotational energy by a crankshaft. As the piston reaches the bottom of its stroke, the exhaust valve opens and the exhaust is expelled from the cylinder by the rising piston.

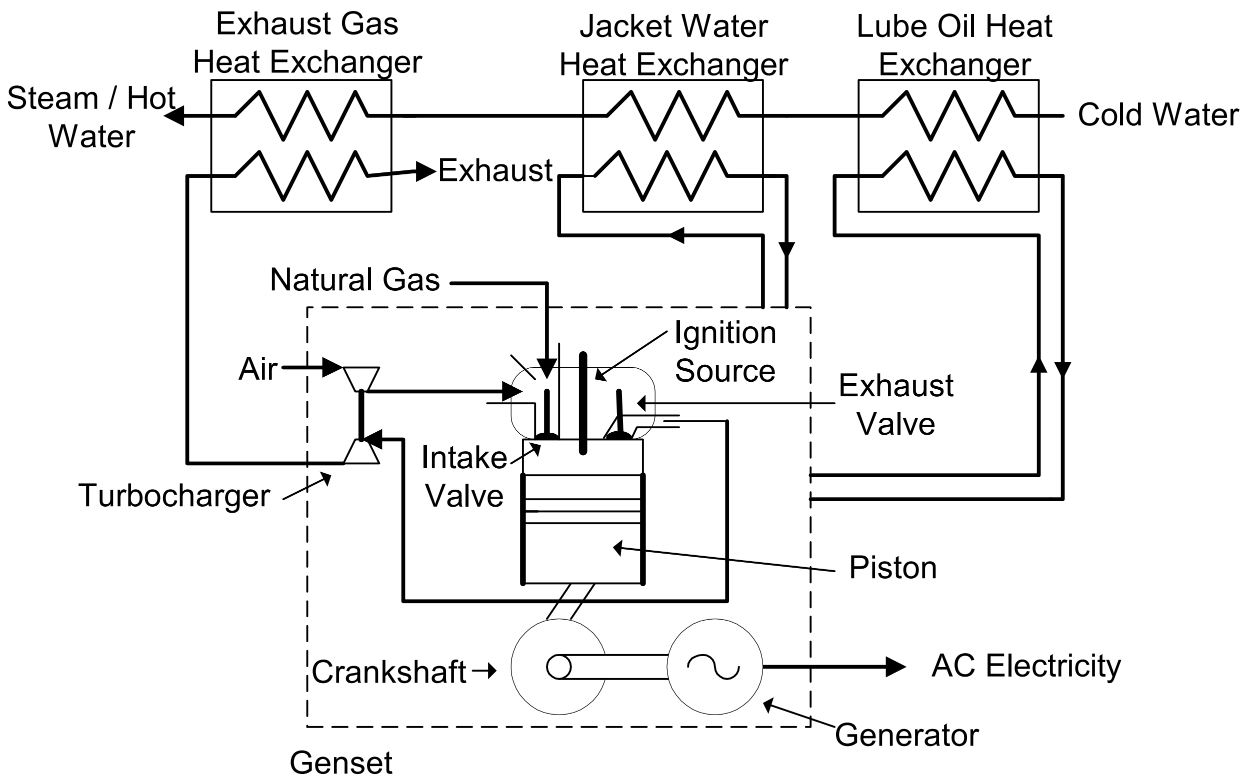


Figure 2-2. Schematic of a Spark Ignited Reciprocating Engine Genset

Both diesel (compression ignition) and natural gas (spark ignition) engines are widespread, but it is becoming increasingly hard to site diesel generators, especially in larger sizes, due to emissions regulations. Most installed natural gas units are stoichiometric (designed for just enough air to allow for complete combustion of the fuel), though newer units, especially in larger sizes, focus on lean-burn technology which allows for excess oxygen and results in increased efficiency and lower emissions from the combustion chamber.

Manufacturers have developed dual fuel engines to take advantage of natural gas emissions, economics, and convenience while keeping the efficiency and reliability benefits of compression ignition technology. These engines are larger units that use a small amount of diesel "pilot" fuel along with the primary natural gas fuel. In lieu of the traditional spark ignition, the diesel fuel is injected into the cylinder along with the natural gas / air mixture in order to initiate combustion. Dual fuel engines are typically more efficient and have lower NO_x and particulate emissions than diesels but have greater emissions than spark-ignited natural gas models. Some manufacturers of dual-fueled models have attempted to reduce emissions by incorporating a pre-ignition chamber that lowers the amount of diesel pilot fuel necessary for ignition.

Engines are characterized by a number of factors such as size, rotational speed, fuel type, and end use application. As Figure 2-3 illustrates, engine sizes range up to 18 MW for 4-stroke engines and up to 65 MW for 2- stoke engines. 2-stroke units normally have an operating speed of approximately 125 rpm where 4-stroke units can range from 300 to 2000 rpm. For a given unit, the higher the rpm, the higher the power output. Therefore, virtually all backup units are high speed (diesels) with higher power-to-size and lower cost-to-power output ratios than their lower speed counterparts. However there generally is a trade off between high rpm and durability, longevity, and frequency of maintenance. Thus most continuous duty units are medium to low speed. Speed also influences the type of fuel that can be used. Lower speed units allow more time for burning of fuel and can be run on lower grade fuels than higher speed units. For this reason heavy fuel oil is often an option for many low speed diesel and 2-stroke engines.

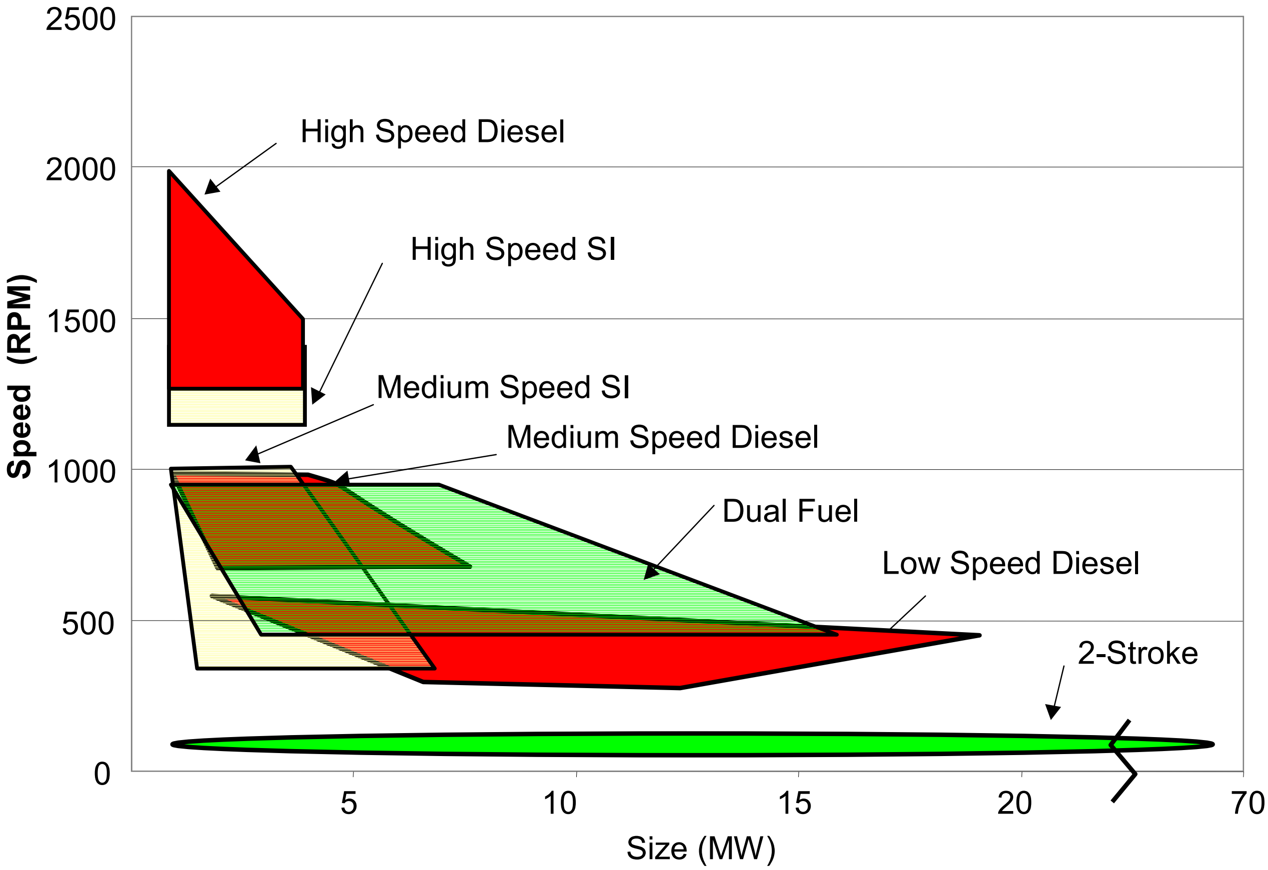


Figure 2-3. Size and Speed of Reciprocating Engines

Figures 2-4 and 2-5 illustrate the size range of the product lines of diesel and natural gas engine manufacturers. Although larger sizes exist, diesels are typically less than 18 MW and almost all natural gas engines are less than 4 MW.

Heat Recovery. Reciprocating engine CHP systems in the industrial sector can be designed to produce steam, hot water, or hot air. Hot water systems are by far the most common type.

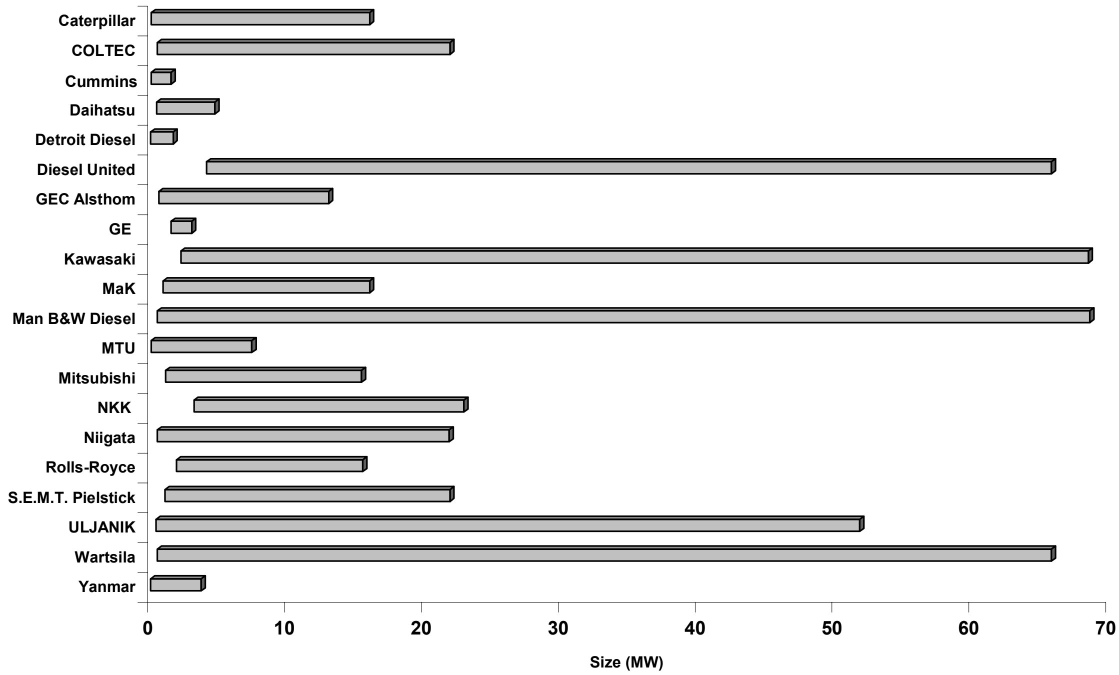


Figure 2-4. Diesel Engine Manufacturers

Source: Diesel and Gas Turbine Worldwide, 2000.

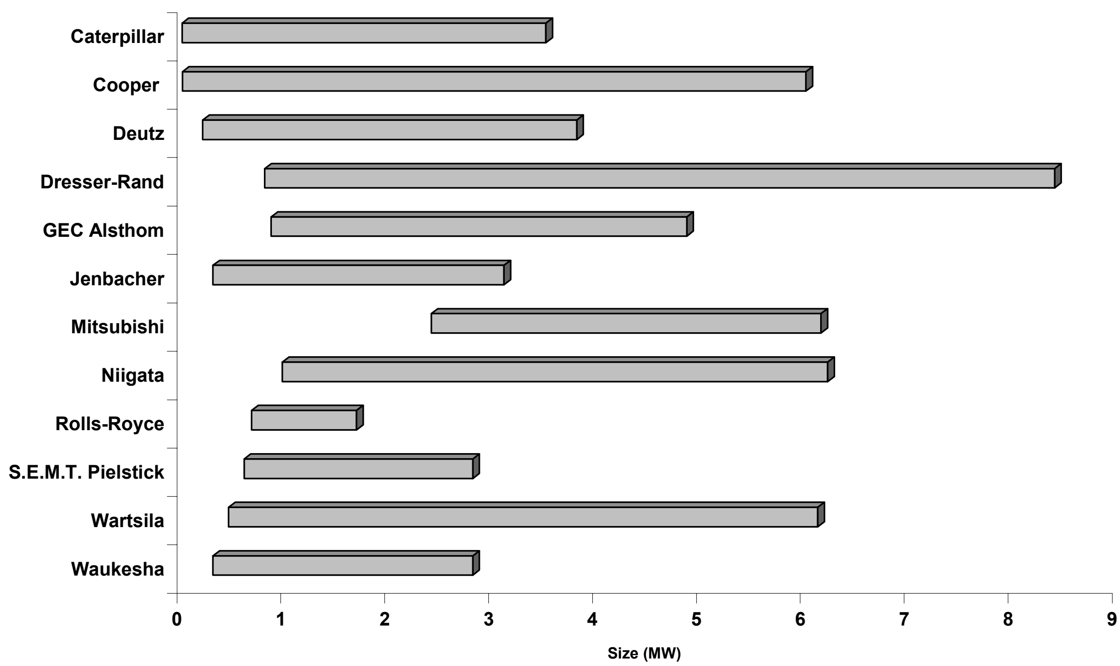


Figure 2-5. Natural Gas Engine Manufacturers

Source: Diesel and Gas Turbine Worldwide, 2000.

There are three types of heat recovery options that can produce steam with reciprocating engines. The standard type of heat recovery option uses liquid-to-water heat exchangers on the water jacket cooling fluid, the lubricating oil system, and sometimes on the aftercoolers and turbocharger. To make steam, an air-to-water heat exchanger is also used on the engine exhaust. With heat recovery from the three liquid-to-water exchangers, water is heated up to 160-180 ^{o}F. The pre-heated water enters the exhaust gas heat exchanger where it is heated up to 180-200 ^{o}F or is evaporated. The exhaust gas energy is about 50% of the total thermal energy produced. Medium size engines usually produce saturated steam of 350-400 ^{o}F, while large units can deliver superheated steam at 480-600 ^{o}F. The minimum exhaust gas temperature at the exit of the heat exchanger is 320- 340 ^{o}F for fuels containing sulfur, like diesel oil, or 190-210 ^{o}F for sulfur-free fuels like natural gas.

Ebullient cooling systems are another way to make steam with reciprocating engines. These systems cool the engines by the circulation of a boiling coolant (usually water) through the engine jacket. The water is then fed through an air-to-water heat exchanger using the engine's exhaust. These systems can produce low-pressure steam (usually no more than 250°F and a maximum of 15 psig). In an ebulliently cooled engine, the coolant (e.g. water) enters the engine as a pressurized liquid at its boiling point. The coolant absorbs heat from the engine and some changes phase (i.e. evaporates). Heat transfer from the engine to the coolant occurs at a constant temperature, leading to lower thermal stress to the engine and thus enhanced engine durability. The coolant in the engine, which is a mixture of liquid and vapor, has a lower density than the coolant that enters the engine, so rises to the top of the engine. After exiting the engine, the coolant enters a steam separator, where steam is separated. The mixture can also be sent to an exhaust gas heat exchanger to produce higher quality steam.

Another way to make steam is to use a forced-circulation system. With these systems, the water in the engine jacket operates at higher than usual pressure and temperature, in the range of 250-270 ^{o}F. These systems can produce steam at slightly higher temperatures and pressures than standard systems.

Units designed to make hot water for industrial applications use a system similar to the first type of steam heat recovery option described above. Water is heated by three liquid-to-water exchangers to 160-180 ^{o}F, and then the water enters the exhaust gas heat exchanger where it is heated up to 180-200 ^{o}F.

Some reciprocating engine systems have cogeneration systems designed to provide heat for drying operations. Products like bricks, ceramics, and animal feed can be dried directly with the engine's exhaust. This is known as "dirty" drying, because of the pollutants in the engine's exhaust. There are also some reciprocating engine CHP systems that use indirect air heating. An air-to-air heat exchanger is used when products, process operations, or the facility environment are potentially compromised by using direct drying/heating systems. These are used for products like food and finish drying and curing systems.

Table 2-1 summarizes some of the development issues that are currently a focus of major engine manufacturers, many of which are the focus of DOE's Advanced Reciprocating Engine Systems (ARES) program. The developments listed below center around meeting the goals of increased efficiency and lower NO_x emissions.

Table 2-1. Key Development Issues for Reciprocating Engines

Issue	Developments
Combustion Chamber Design	Combustion chamber design is important to the efficient and complete combustion of fuels and the reduction of NO_x emissions. Advances such as a precombustion chamber to mix air and fuel or partially combust fuel prior to introduction into the main combustion chamber may be key to successful low NO_x, lean-burn engines.
Fuel Injection/ Timing	How fuel is injected and when in the cycle it is injected play important roles in how the fuel is combusted and therefore influence power, efficiency, and emissions. Rolls-Royce has developed a unique system that utilizes variable injection rate shaping and precise volumetric fuel control to optimize combustion for either low emissions or high efficiency.
Cylinder Head/Valves	Cylinder head and valve design has a significant influence on engine power, efficiency, and emissions. Intake systems need to provide substantial airflow and produce proper airflow patterns to facilitate combustion. Exhaust systems must be designed to allow the exhaust to be pumped out of the cylinder with a minimum of work and minimal heat transfer to the cylinder head and coolant. Waukesha has expended significant R&D effort in this area and has made advancements including water cooled exhaust seats, improved valve and valve seat materials, and a cooler head deck.
Higher Power Density	Effective turbocharging is key to increasing Brake Mean Effective Pressure (BMEP) which leads to increased efficiency. Turbocharged engines, which compress intake air before injection into the combustion cylinder, can achieve greater power to size ratios (power density), allowing units to be sited in a smaller area and/or lessening foundation reinforcement requirements. Achieving higher power density may also be key to reducing per kW cost, but may require more durable engine components.
Engine Durability	Improving reliability and durability, especially with increased compression ratios and BMEP, will require higher strength and temperature resistant components. Engine manufacturers are therefore investing research into stronger valves, crankshafts, cylinder liners, reinforced pistons, and cylinder head structure. Ceramic valve inserts have already been shown to extend cylinder head life (Caterpillar). In addition to making the components stronger, other developments to increase component durability and life include improved cooling of turbochargers, valve seats, and the area around the spark plug. Thicker combustion walls and bore cooling can also compensate for increased temperatures resulting from increased output. More durable components should also reduce maintenance expense.
Advanced Sensors and Controls	Waukesha has been developing ignition controllers coupled with detonation sensors to provide optimum individual cylinder timing. In addition, they are also developing protection from detonation that can result from retarded ignition timing and precise air/fuel ratio controllers to monitor exhaust oxygen content and adjust the amount of fuel accordingly to maintain efficiency and low emissions as engine load, speed, fuel pressure and fuel quality change. Cummings has developed the PowerCommand Control system that is integrated to control, monitor, and provide diagnostics. The system replaces separate voltage regulators, governors, protective relays, synchronizers and load sharer. Additionally through integration of fuel and alternator control, frequency and voltage overshoot are reduced resulting in a reduction of black smoke at start-up.

Ignition	Most diesel and dual-fuel engines are compression ignited. Some advanced diesels and almost all gasoline and natural gas units are spark ignited. High efficiency engines will operate at higher pressure levels which will require high-energy spark ignition systems with durable components. Glow plugs and lasers are also employed as ignition sources for natural gas engines. Laser ignition has the potential to improve fuel efficiency and lower emissions by improving ignition timing and placement in addition to reducing maintenance requirements and increasing reliability. Micropilot ignition, where a very small amount of burning pilot fuel serves as an ignition source for the primary fuel, is also being explored by manufacturers (Cooper, Wartsila). Waukesha has employed a flange mounted coil which improves spark delivery, eliminates water intrusion into the spark plug well and reduces costs. Cooper has also developed a long-life iridium spark plug.

Turbines

Figure 2-6. Rolls-Royce Allison 501-K Turbine Power Package

Combustion turbines have been used for power generation for decades, and range in size from simple cycle units starting at about 1 MW up to several hundred MW when configured as a combined cycle power plant. Units from 1-15 MW are generally referred to as industrial turbines, differentiating them from larger utility grade turbines and smaller microturbines. Units smaller than 1 MW exist, but few have been installed in the U. S. Microturbines (up to 500 or 600 kW) promising low emissions, relatively low maintenance, and other benefits are emerging and will provide competition for smaller reciprocating engines. Miniturbines (500-1,000 kW) are rarely used in the U.S., and are more common in Japan for backup power installations. Traditionally, turbine applications have been limited by lower electrical efficiencies to combined heat and power uses at industrial and institutional settings and peaking units for electric utilities.

Combustion turbines feature relatively low installed cost, low emissions, and infrequent maintenance. With these advantages, combustion turbines are typically used in industry when a continuous supply of steam or hot water and power is desired. Some applications use turbines solely for power generation, when emissions from natural gas reciprocating engines are seen as a disadvantage. Few turbines are used by industry for emergency, standby, or peak shaving applications, mostly due to their lower electrical efficiency and longer startup time when compared with reciprocating engines. Some users, however, have shown a preference for turbines for emergency uses due to perceptions of starting reliability.

Industrial turbines have historically been developed as aero derivatives, spawning from engines used for jet propulsion. Some, however, have been designed specifically for stationary power generation or compression applications in the oil and gas industries. Figure 2-7 illustrates the components of an industrial turbine. Multiple stages are typical and differentiate these turbines, along with axial blading, from smaller microturbines, which currently have radial blades and are single staged. The intercooler shown on this figure is not necessarily typical, and is usually reserved for larger turbines that can economically incorporate the cost of this improvement in efficiency.

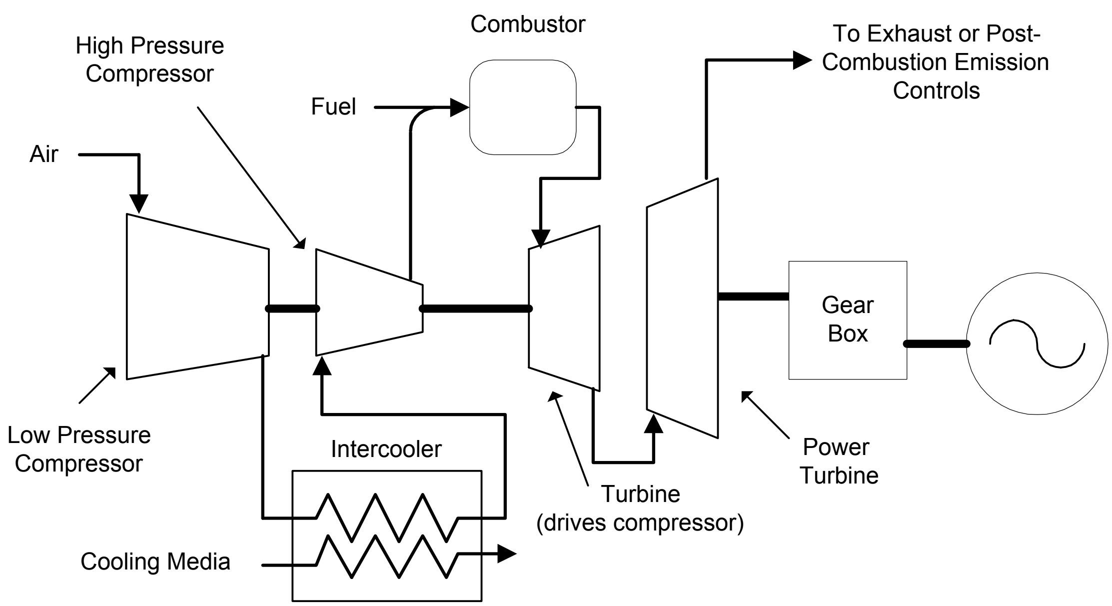


Figure 2-7. Schematic of a Turbine Genset

Given that combustion takes place outside of the turbine area (unlike reciprocating engines, where combustion takes place inside the cylinder), turbines have more flexibility in reducing NO_x emissions. NO_x emissions from uncontrolled turbines range from 75 to over 150 ppm, due to high combustion temperatures. Emissions control of combustion turbines has typically been accomplished by water or steam injection to reduce the combustion temperature and reduce NO_x levels down to 25-45 ppm. These methods increase power production, but reduce the system efficiency. While these means have been proven effective in limiting NO_x emissions, the availability of water supply and space for storage tanks are constraints for some applications. In many states, these measures are deemed adequate to meet NO_x regulations.

Figure 2-8 illustrates the size ranges of the product lines of turbine manufacturers.

Heat Recovery. Industrial-sector turbine CHP systems can be designed to produce steam, hot water, or hot air. Steam systems are the most common type, because of the high quality waste heat available and the high demand for steam in many industries.

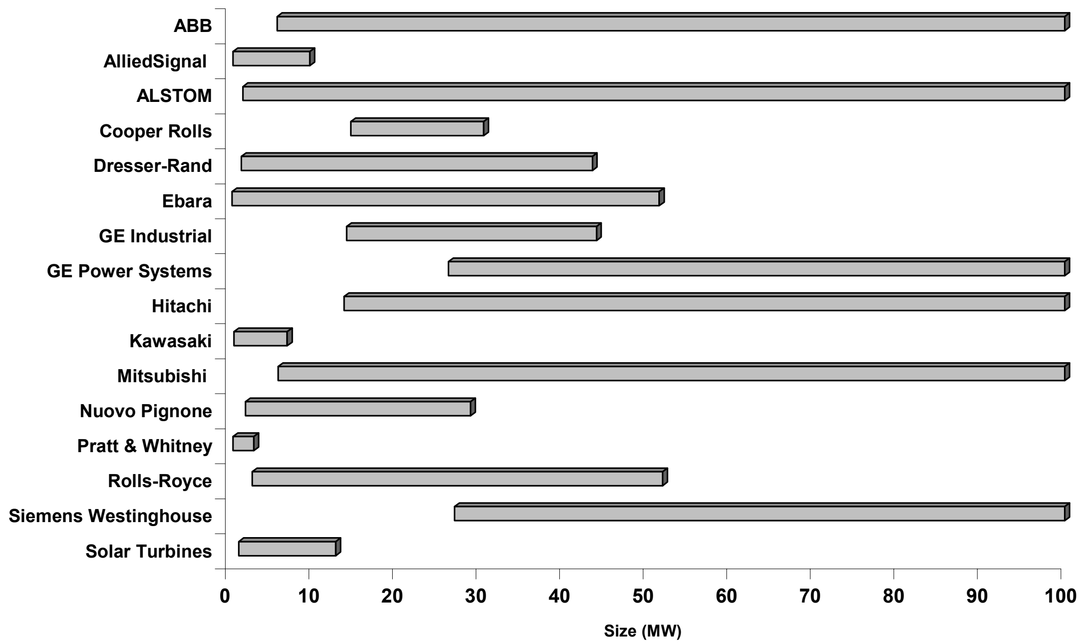


Figure 2-8. Turbine Manufactures

Hot exhaust gas from the exhaust of a simple cycle combustion turbine can be used to make steam or hot water by adding a heat recovery steam generator (HRSG). Because of the high quality waste heat available in the exhaust gas, high-pressure steam suitable for many industrial processes can be generated. The exhaust gas at 1,000-1,050^{o}F is cooled in the HRSG to about 300^{o}F to extract heat. A temperature of 300 ^{o}F is maintained at the outlet of the HRSG to avoid condensation of exhaust gases. At lower temperature levels, gases such as SO_x and NO_x would form acids and combine with water condensation to corrode the HRSG.

The basic heat-to-power ratio of a simple gas turbine cogeneration system is about two. Since a turbine's exhaust gas is also oxygen rich, it can support additional combustion through supplementary firing in the HRSG. Supplementary firing can increase the heat-to-power ratio to about four. An HRSG unit with supplementary firing contains additional burners to increase the heat output and requires additional fuel. Supplementary firing is common in many industrial sector gas turbine CHP systems.

Turbine exhaust can also be used directly for industrial heating and drying operations. It can be used in specially-designed equipment like dryers, kilns, calciners, and ovens. Products like gypsum, plasters, cements, limestone, bricks, glass and mineral wool can be heated or dried using turbine exhaust. As with reciprocating engines, direct use of the exhaust is known as "dirty" drying/heating, because of the pollutants in the exhaust steam (although in some turbine applications like greenhouse heating the pollutant carbon monoxide is desirable, and thus the exhaust is not thought of as "dirty"). An air-to-air heat exchanger can used when products, process operations, or the facility environment are compromised by using direct drying/heating systems.

Key development issues for turbines are summarized in Table 2-2.

Table 2-2. Key Development Issues for Turbines

Issues	Developments
Improved Materials	More durable and temperature resistant materials are needed in order to increase the operating temperature of turbines. Materials with higher creep strength and greater resistance to thermal fatigue, oxidation, and thermal corrosion (ceramics, directionally solidified material, and single-crystal superalloys) are needed. These materials will allow for a higher compression ratio and/or higher temperatures leading to higher efficiency. Additionally, longer-lasting components can lead to less down-time and maintenance expense. The development of ceramics and technologies for applying these and other advanced materials for use in first stage turbine blades coatings and combustor liners may also improve the performance and economics of turbines. Additionally, lower manufacturing costs are needed although these costs may decrease as the number of ceramic components purchased increases. Ceramic components are critical to the Solar Turbine Mercury 50. Nuovo Pignone has incorporated aero-derivative materials (from GE) for blades and vanes to handle increased temperatures (2,190^{o} F).
Recuperation	Recuperators are air-to-air heat exchangers that use turbine hot exhaust gases to preheat the combustor inlet air after it has been compressed. Recuperators have already been employed in microturbines with recuperated unit electric efficiencies typically between 26 and 32% versus 15-22% for non-recuperated units. More effective and higher temperature recuperators will be needed in order to realize efficiency goals (40%+). Although currently not commonly employed for turbines in the >1 MW size range, recuperation is key in the ATS program and is also used in a new Dutch (OPRA) design.
Intercooling	Intercooled turbines have a two (or more) stage compression process in which the compressed air is cooled between stages. This lowers the work needed by the compressor and produces lower temperature air for better cooling of turbine parts. The net result is an increase in power and efficiency. Solar Turbines has identified an intercooled and recuperated unit to meet ATS Phase II goal of 50% efficiency. GE currently offers a simplified version of intercooling with its LM6000 turbines with “Sprint” technology. “Sprint” equipped units inject water into the compressor increasing mass and cooling the air, yielding a 10% increase in power output and a modest increase in efficiency. Northrop Grumman Marine Systems and Rolls-Royce are developing the WR-21, a intercooled, recuperated (ICR) gas turbine engine system for the U.S. Navy to be used for surface ships.
Advanced Cheng Cycle Units	A steam injected turbine cycle developed by Cheng Power Systems has been applied to projects in the US and overseas. The process injects steam produced from the exhaust gas into the gas turbine, increasing mass flow and decreasing the effects of higher ambient temperature. The cycle also allows for a higher firing temperature (up to 2,650^{o}F currently) and quicker augmentation of power (versus combined cycle).
CHAT Technology	Cascaded Humidified Advanced Turbine (CHAT) technology can increase output and has a higher efficiency at part load than simple or combined cycle units. The technology has not been demonstrated though there is a proposal under the Flexible Gas Turbine System initiative program to do so. Current targets are for $700-$750/kW for a 46.4% efficient 12 MW plant.

Improved Cooling	Improved cooling allows for higher firing temperatures and longer component life. Types of advanced cooling schemes include transpiration cooling and vortex cooling. Transpiration cooling, which is being developed by Rolls-Royce Allison for their high pressure turbine, allows for higher turbine inlet temperature with the use of less air. Vortex cooling, as used by Solar's Mercury 50, uses swirled airflow through the leading edge cooling circuit of turbine blades. ABB ALSTOM Power has also expended much effort in this area examining multiple methods of blade cooling methods/configurations (triple-pass, quadruple-pass, single LE with triple pass, etc.).
Ability to Burn Low-Value Fuels	Gasifiers produce gaseous fuel from solids, such as coal and biomass. Gasifiers could help turbines gain wider acceptance, especially in international markets and where no natural gas supply exists. Gasifiers potentially also can lower operation costs by allowing the turbine to be run on less expensive fuels. However, gasifers generally use fuel with impurities and/or contaminants, and thus require expensive fuel gas cleanup that can severely compromise efficiency.
Retained Power Output (at elevated ambient temperatures)	Peak turbine use is normally during high temperature periods where maximum output is lowest. Current methods to lessen the effects of ambient temperature include evaporative cooling and mechanical or adsorption inlet air chillers, or steam injection. Newer methods include using compressed air storage and injecting compressed air upstream of the combustor when power augmentation is needed.
Easier Maintenance	Easier access to unit components reduces downtime and maintenance expense. Modular construction used by Rolls-Royce, Solar and others for some models allows for quick changeout and ease of shipment and installation. Additionally, maintenance expense can be lessened if components within each module are designed to need maintenance at the same time or in multiples of each other. Another way to decrease maintenance expense is by increasing the number of boroscope ports, such as is being done by Pratt & Whitney. Additionally, maintenance expense and downtime can be reduced through advanced monitoring of turbine performance, which can allow for longer times between maintenance as service is only performed when necessary.
Dry Low Emissions	Reducing NO_x emissions from the combustion chamber without the use of water or steam injection is known as Dry Low NO_x. These technologies center on achieving ideal combustion and therefore also frequently reduce CO emissions. Most designs employ a lean-premix approach which mixes fuel and air together prior to introduction into the combustion chamber. Some designs partially combust the fuel in a high-temperature / fuel-rich precombustion chamber to separate high-temperature and fuel-lean combustion processes which, together, lead to the formation of NO_x.
Catalytic Combustion	Catalytic combustion has been demonstrated and is nearing commercialization. The key to the technology is the elimination of a flame through catalyst aided combustion. Although costs are projected to be lower than the combination of Dry Low emissions and selective catalytic reduction, lowering costs would speed commercialization. R&D is still needed to allow this technology to be used with more efficient high temperature, high pressure units.
$SCONO_x$	This technology, developed by Goal Line Environmental Technologies LLC uses a proprietary oxidation/absorption/regeneration process to reduce NO_x, CO, and VOCs without the use of potentially harmful reducing agents such as ammonia. This technology has demonstrated NO_x emissions of .75 ppm. ABB Environmental has recently guaranteed emissions performance and the technology has been named Lowest Achievable Emissions Reduction (LAER) by the EPA.

Fuel Cells


From FuelCells.org

Figure 2-9. Fuel Cell Energy's 2MW Molten Carbonate Fuel Cell power plant demonstration in Santa Clara, California

Fuel cells are an emerging small-scale power generation technology, mostly under 1 MW although larger applications do exist. The first fuel cell was developed in 1839 by Sir William Grove. However, they were not used as practical generators of electricity until the 1960's when installed in NASA's Gemini and Apollo spacecraft. One company, UTC Fuel Cells, currently has a number of their 200 kW phosphoric acid fuel cells in use in both commercial and industrial applications. A number of other companies are currently field testing demonstration units, and commercial deliveries are expected in 2003-2005. Although fuel cells were first designed as purely electric generators, there are transportation applications. Automobile manufacturers through in-house R&D and alliances with fuel cell manufacturers are increasingly funding fuel cell development. Currently most transportation fuel cell efforts focus on Proton Exchange Membrane (PEM) fuel cells that have a good power to volume ratio. PEMs also have some potential for providing stationary power, mostly for residential or commercial applications. Fuel cells primarily used for power generation, such as Phosphoric Acid, Solid Oxide, and Molten Carbonate, are generally not suited for transportation use.

There are a number of types and configurations of fuel cells, but they all use the same basic principle. As shown in Figure 2-10, a fuel cell consists of two electrodes separated by an electrolyte. Hydrogen fuel is fed into the anode of the fuel cell. Oxygen (or air) enters the fuel cell through the cathode. With the aid of a catalyst, the hydrogen atom splits into a proton and an electron. The proton passes through the electrolyte to the cathode. As they flow through an external circuit connected as a load, and return to the cathode, the electrons create a DC current. At the cathode, electrons combine with hydrogen and oxygen producing water and heat. The part of a fuel cell that contains the electrodes and electrolytic material is called the "stack" and is a major component of the cost of the total system. Stack replacement is very costly but becomes necessary since efficiency degrades as stack operating hours accumulate.

Representative Manufacturers
UTC Fuel Cells
Ballard Generation Systems
FuelCell Energy
Siemens Westinghouse
Plug Power

Fuel cells require hydrogen for operation. Since it is currently impractical to use hydrogen directly as a fuel source, it must be extracted from other hydrogen-rich sources such as gasoline or natural gas. Cost effective, efficient fuel reformers that can convert various fuels to hydrogen are necessary to allow fuel cells increased flexibility and better economics. Some molten carbonate and solid oxide fuel cells employ internal reforming which eliminates the expense of an external reformer. Fuel cells have very low levels of NO_x and CO emissions, all resulting from the reforming process. Using gasifiers to produce hydrogen fuel from sources such as biomass could help to increase flexibility and market share of fuel cells.

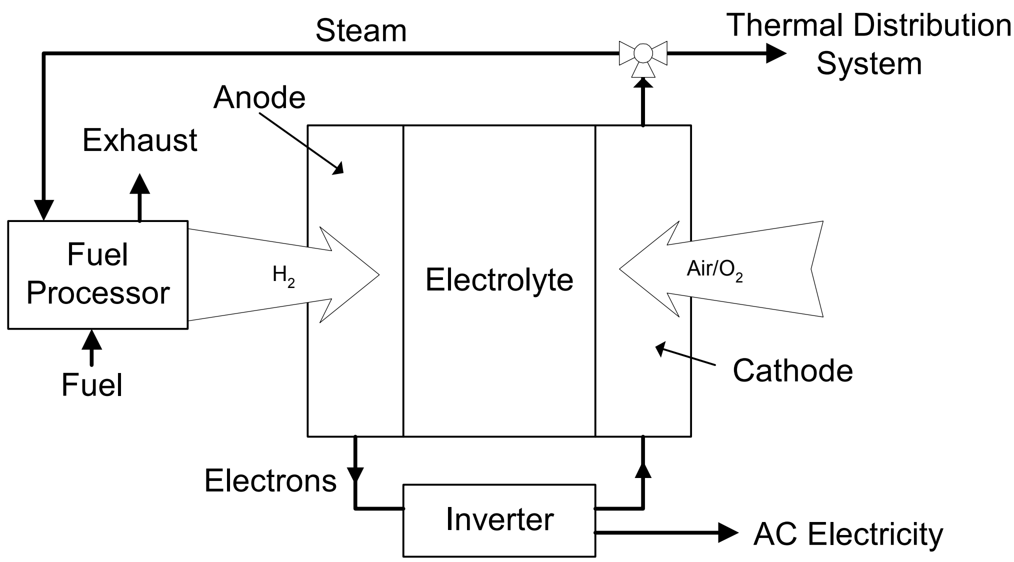


Figure 2-10. Schematic of a Typical Fuel Cell

The main differentiation among fuel cell types is in the electrolytic material. Each different electrolyte has benefits and drawbacks based on cost, operating temperature, achievable efficiency, power to volume (or weight) ratio and other operational considerations. Currently only Phosphoric Acid fuel cells are being produced commercially for power generation. Other types have entered the testing and demonstration phase and it is likely that solid oxide and molten carbonate fuel cells will be the major players in the larger (>1 MW) size range.

Heat Recovery. The phosphoric acid fuel cell can be used in two different types of industrial cogeneration applications: to produce hot water at around 140° F, or to produce hot water at around 140° F and low temperature steam at 250° F. Overall efficiency for both is around 80-85 %.

Unlike with the development of other technologies, fuel cell development is focused more on getting units to work and demonstrating effectiveness rather than refining current models. Table 2-3 briefly describes the key issues for the different fuel cell types.

Table 2-3. Key Issues for Fuel Cells

Configuration	Explanation
Molten Carbonate	Molten carbonate fuel cells (MCFCs) promise high fuel-to-electricity efficiencies and the ability to consume coal-based fuels. This cell operates at about 1200°F (up to 1,400°F). Molten carbonate stacks have been proven, and demonstration units are currently being tested. Molten carbonate fuel cells are most applicable to large industrial and central station electricity generation. Minimal polarization losses allow the cells to use less expensive, non-noble metal catalysts. Because of their high operating temperature, MCFCs also produce high quality waste heat, which can be used in fuel processing and cogeneration. FuelCell Energy is the most visible manufacturers of this technology.
Solid Oxide	Another highly promising technology, the solid oxide fuel cell, could be used in big, high-power applications including industrial and large-scale central electricity generating stations. Small units (25-100 kW) are currently being demonstrated. A solid oxide system usually uses a hard ceramic material instead of a liquid electrolyte, allowing operating temperatures to reach 1,800°F. Power generating efficiencies could reach 60%. One type of solid oxide fuel cell uses an array of meter-long tubes. Other variations include using compressed discs. Carbon monoxide can also be used instead of hydrogen in these fuel cells to produce carbon dioxide and electrons in the anode. Siemens Westinghouse Power Corp. is probably the most noted manufacturer of this type of fuel cell.
Turbine / Fuel Cell Hybrids	Power generation systems utilizing fuel cells combined with turbines are also being developed by some manufacturers. These systems typically run the hot gas produced by certain types of fuel cells (primarily SOFC or MCFC) through a turbine to generate additional electricity. Hybrid systems are predicted to have exceptionally high electric efficiencies (60%-70%), and can potentially be developed for CHP applications.

Process Cooling

Process cooling refers to a direct process end use in which energy is used to lower the temperature of substances involved in the manufacturing process. Conventional equipment includes industrial chillers and absorption cooling equipment. Process cooling is used for:

- Refrigerated storage of unfrozen foods,
- Frozen foods,
- Cooling to change the chemical structure of food,
- Freeze drying,
- Industrial process air conditioning, and
- Cooling in the petroleum and chemicals industries (reaction heat removal, gas separations, condensation of gases, separations, solidifications, humidity control, etc.).

Absorption Chillers. Absorption cooling systems require a source of heat. In conventional absorption systems, this heat is supplied by steam heat exchangers, an electrical heater, or a gas-fired heater. For cogeneration systems, this heat can be supplied using a heat exchanger with clean exhaust gases from a turbine or other type of prime mover as a heat source. The heating gases may have to be mixed with air or other gases to maintain desired heating gas temperature. Such a system can provide all or a portion of the needed heat input for the overall system.

Absorption chillers use heat to boil a solution of refrigerant/absorbent. Most CHP systems with absorption chillers use water and lithium bromide for the working solution, although some direct-fired (non-CHP) absorption systems use ammonia and water. The absorption chiller then captures the refrigerant vapor from the boiling process, and uses the energy in this fluid to chill water after a series of condensing, evaporating, absorbing steps are performed. This process is essentially a thermal compressor, and replaces the electrical compressor in a conventional electric chiller, significantly reducing the electrical requirements, requiring electricity only to drive the pumps that circulate the solution. The process is employed by single-effect chillers.

Double-effect units are available which add another boiling and condensing step at a higher temperature, thus attaining higher efficiencies. Single-effect units offer coefficient of performances (COPs) of about .7, where double-effect units attain levels of about 1.2, about 70 percent higher. Double-effect units, however, require a higher temperature source that cannot be provided by some CHP systems, particularly smaller reciprocating engines and fuel cells. In addition, both direct-fired (typically natural gas) and indirect-fired (typically using steam or hot water) units are available. As the focus of this study is on units that work with a wide range of CHP systems, single-effect, indirect-fired absorption chillers are the only option considered in the market analysis.

While the absorption chiller technology has been around since the late 1800s, historically the manufacturing base for these units was largely in Japan. Japan developed these units to help reduce dependency on high cost imported fuels, and recognized the benefits of the higher efficiency levels that could be attained. During this period, availability and lead time for U.S. orders lagged behind that of conventional electric chillers, and thus only a small niche market emerged. In the 1990s, however, several of the largest U. S. manufacturers of electric chillers developed absorption products, and were able to reduce costs and lead times, and improve availability. As a result, the market for absorption chillers has been growing

Engine-Driven Chillers. Engine-driven chillers (EDCs) are basically conventional chillers driven by an engine, in lieu of an electric motor. They employ the same thermodynamic cycle and compressor technology that electric chillers use, but use a gas-fired reciprocating engine to drive the compressor. As a result, EDCs can be economically used to provide refrigeration where gas rates are relatively low and electric rates are high. Another benefit offered by EDCs are the better variable speed performance, which yields improved part-load efficiencies. EDCs operate in a CHP system when the waste heat produced by the engine is recovered, and used for hot water loads.

Like conventional electric chillers, EDCs are available with three different types of compressors. In EDC units under 200 tons, reciprocating compressors are typically packaged with the engine. In applications ranging from over 200 tons to less than about

1,200 tons, both screw and centrifugal compressors are used. In the largest sizes over 1,300 tons, centrifugal compressors are the only option.

As with reciprocating engine generators, EDCs offer options of heat recovery for CHP systems, although in the market analysis only EDCs without heat recovery were considered.

Section 3
MARKET POTENTIAL FOR INDUSTRIAL COOLING, HEATING AND POWER

Combined Heat and Power (CHP) applications, also known as cogeneration, use distributed generation (DG) technologies such as reciprocating engines or industrial turbines to generate power for on-site use while also utilizing otherwise wasted exhaust heat as useful thermal output. Typically, hot water or steam is generated from the waste heat and used for process heating, but the waste heat can be directed to an absorption chiller where it can provide process or space cooling. Furthermore, for the purpose of this study, engine-driven chillers are considered cooling, heating and power applications since they provide thermal output, in the form of process or space cooling, and also displace electricity that typically would be purchased to provide this cooling.

Baseload power applications of DG technologies are also considered, to ensure that the analysis does not miss potential applications that could employ onsite power generation, but where thermal needs are small or straight power generation is simply more economic. Baseload power, like CHP, generally requires power on a nearly continuous basis, typically at least 6,000 hours per year. Competing grid price and the installed cost of the unit are the primary drivers of baseload power economics. Operating cost, power quality, and reliability are also contributing factors.

Other potential uses of DG technology include peak shaving, premium power, and "green" power. However, given the study objective of assessing the most likely markets for CHP technology, the focus was on combined heat and power applications with baseload power also included.

The Economics of Combined Heat and Power

To determine the potential for CHP in the U.S. industrial sectors, this effort evaluated a wide range of DG units up to 50 MW in size. The study focused on units due for production by year 2002 (base case scenario), and included reciprocating engines, industrial turbines, microturbines, combined-cycle turbines, and phosphoric acid fuel cells. A future case was evaluated as a sensitivity that considered significant improvements in cost and performance for each of these technologies, as well as the emergence of solid oxide fuel cells. Tables A-1 and A-2 in Appendix A document the assumptions regarding the improvements in unit cost and performance for both the base and future cases.

The analysis determines not only whether on-site generation appears to be more cost effective than purchasing from the grid, but also which technology, application, and size appears to be the most economical. As a result, double counting of market potential for a variety of competing technologies is avoided. Using data on the number of facilities in each size range and energy prices from the largest 68 utility service territories (in terms of industrial electricity sales), the

market potential for CHP installations is then determined. Appendix A provides a discussion of the study inputs, analysis methodology, and outputs.
To illustrate how combined heat and power can be economical, the cost-to-generate a kWh of electricity was calculated by dividing all generating costs including installed equipment, operation and maintenance, and fuel by the amount of generation. This calculation was performed for baseload power generation (without heat recovery) and CHP. Figure 3-1 illustrates how baseload cost-to-generate varies with natural gas price, with inputs based on the unit cost and performance data shown in Table A-1 for a variety of engines, turbines, fuel cells, and combined cycle units.

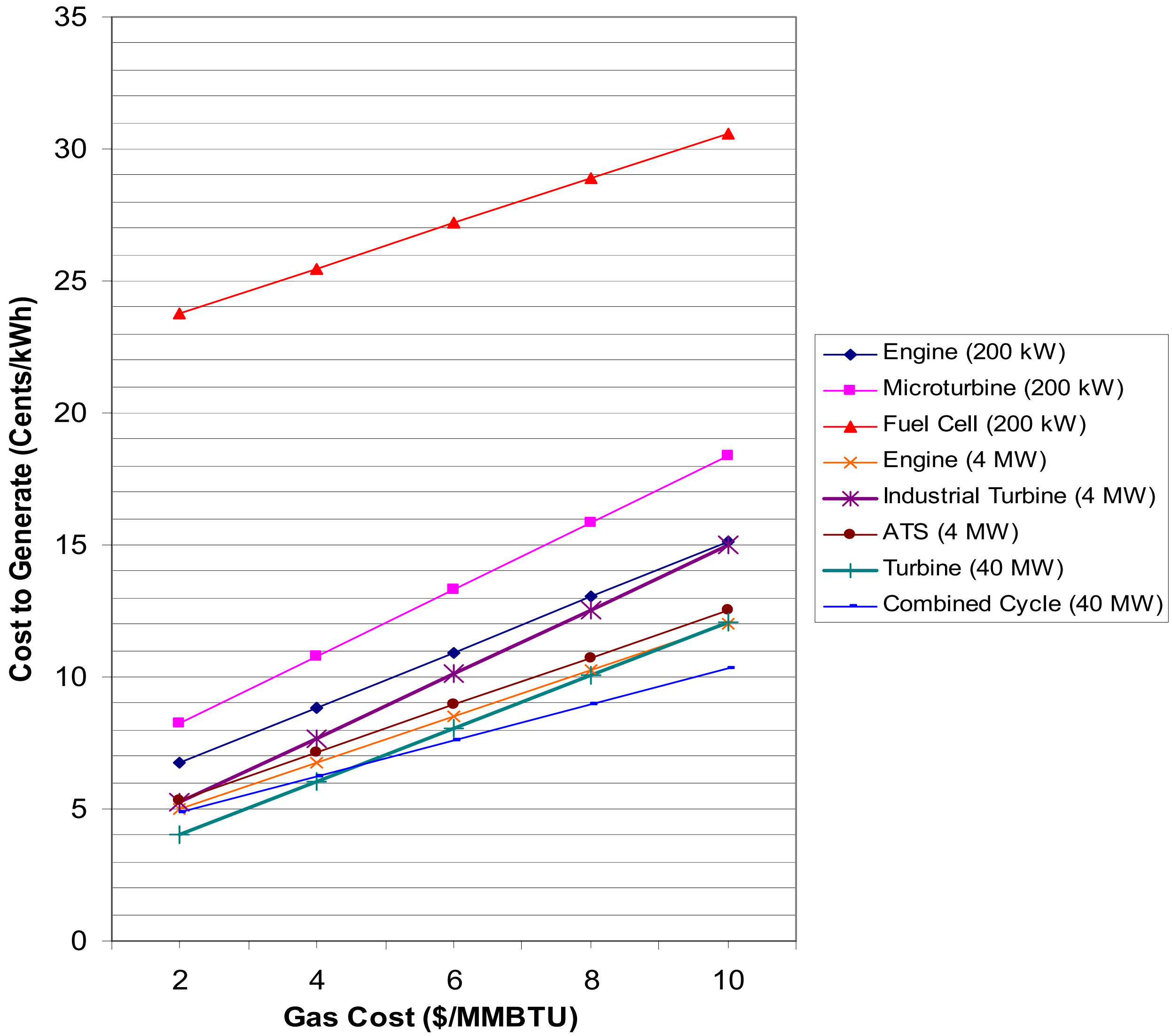


Figure 3-1. Baseload (Non-CHP) Cost-to-Generate by Various Technologies and Sizes (Cents/kWh)

Installed equipment costs are incorporated into the cost-to-generate by dividing the installed costs by the hours of operation, with the installed cost first portioned into a yearly cost through a 5-year capital lease payment based on 9 % interest. Figure 3-1 illustrates the cost-to-generate assuming 65 % capacity factor (5,694 hours annually) and baseload operation. Combined cycle units have the lowest cost-to-generate at all gas costs but below \$4/MMBTU. At gas costs below \$4/MMBTU, the lower capital cost of similar sized simple cycle turbines allows them to offer the lowest cost-to-generate. In smaller sizes, such as 4 MW, engines offer the lowest baseload cost to generate due to their high electrical efficiency, followed closely by Advanced Turbine Systems (ATS) units. Similarly, engines are also the most competitive baseload power option in the 200 kW size range, with better electrical efficiency than microturbines and much lower installed cost than phosphoric acid fuel cells. Obviously, the lesson here is that only large units and relatively low gas prices (\$2-4/MMBTU) can compete with grid prices (avg. 5-6 cents/kWh) using baseload operation. Higher (80-90 %) capacity factor operation also helps lower the cost-to-generate and enable these units to better compete with grid prices.

Figure 3-2 depicts the cost-to-generate when CHP operation is considered. This time, units are given full credit for recovered waste heat, based on the cost of producing the thermal output using an 80 % efficient boiler. While not considered in Figure 3-2, some applications may require steam of higher quality and may not be able to fully value all thermal output from technologies that produce lower quality steam or hot water, such as reciprocating engines.

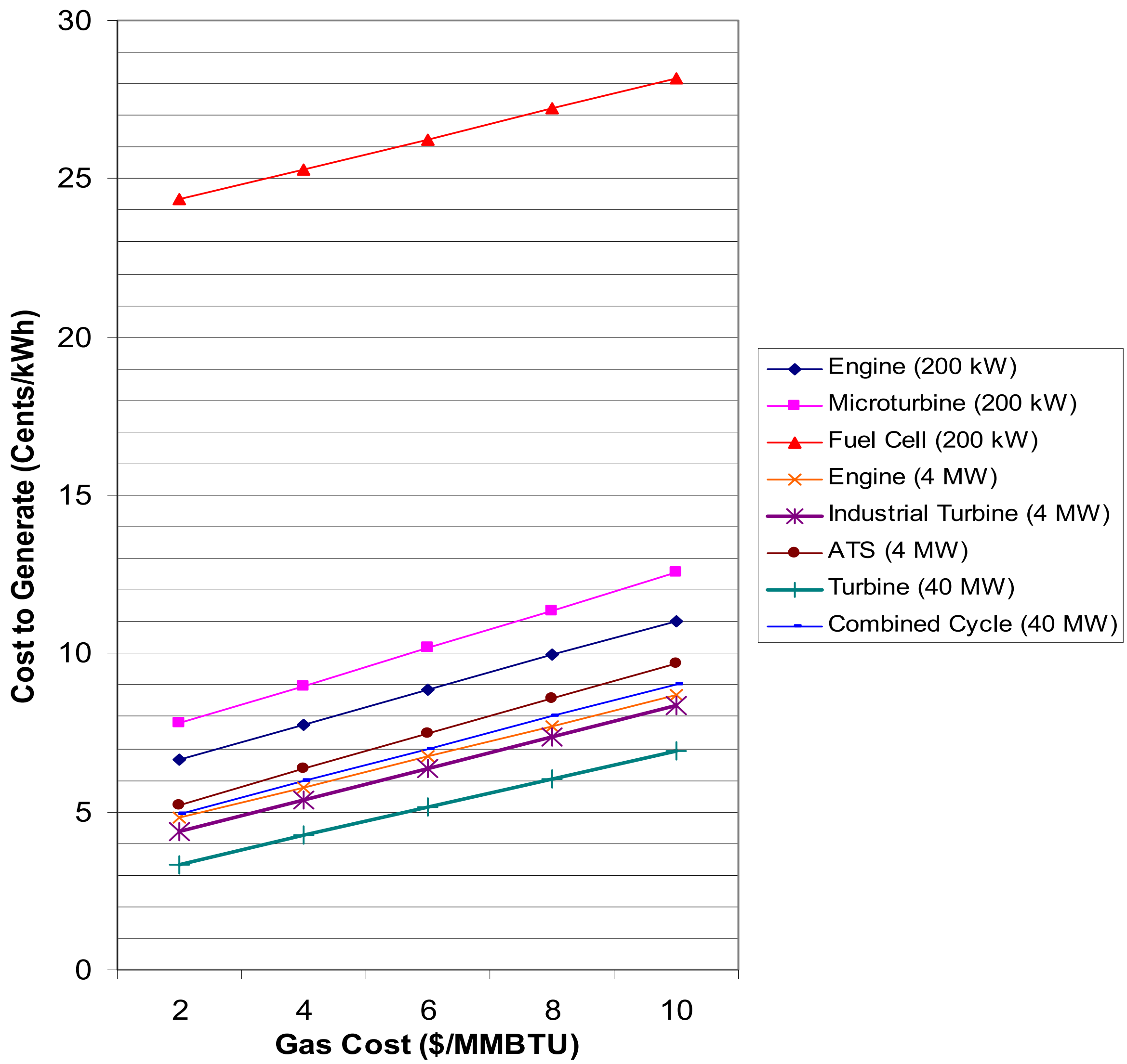


Figure 3-2. CHP Cost-to-Generate by Technologies of Various Sizes (Cents/kWh)

When CHP operation is considered, turbines (both larger 40 MW size and smaller 4 MW industrial size units) offer the lowest cost-to-generate. Both of these units post sub 6 cents/kWh values at gas costs below $5/MMBTU, which illustrates why turbines are often employed for CHP duty. Engines and ATS costs are somewhat higher but also competitive. In the small sizes (200 kW), engines offer a lower cost to generate than microturbines, but this is largely based on the currently-higher installed cost of microturbines, which is expected to fall somewhat as production volumes increase. Furthermore, the generating economics of any of the units shown in Figure 3-2 improve with higher (80-90 %) capacity factors.

Figure 3-3 summarizes the cost-to-generate for a 4 MW unit using \$4/MMBTU gas cost and 65 % capacity factor. For baseload operation, engines offer the lowest cost-to-generate, with ATS somewhat higher and turbines the highest. With CHP applications taking full credit for the avoided boiler fuel, the cost-to-generate falls for all the DG technologies, but due to relative electrical and thermal efficiencies, turbines gain the most of the three technologies. The general finding is that non-CHP operation favors engines and ATS at all but the lowest gas prices (i.e. under \$4/MMBTU), but turbines are the most economic technology for CHP applications at any gas price, assuming all the thermal output has value.

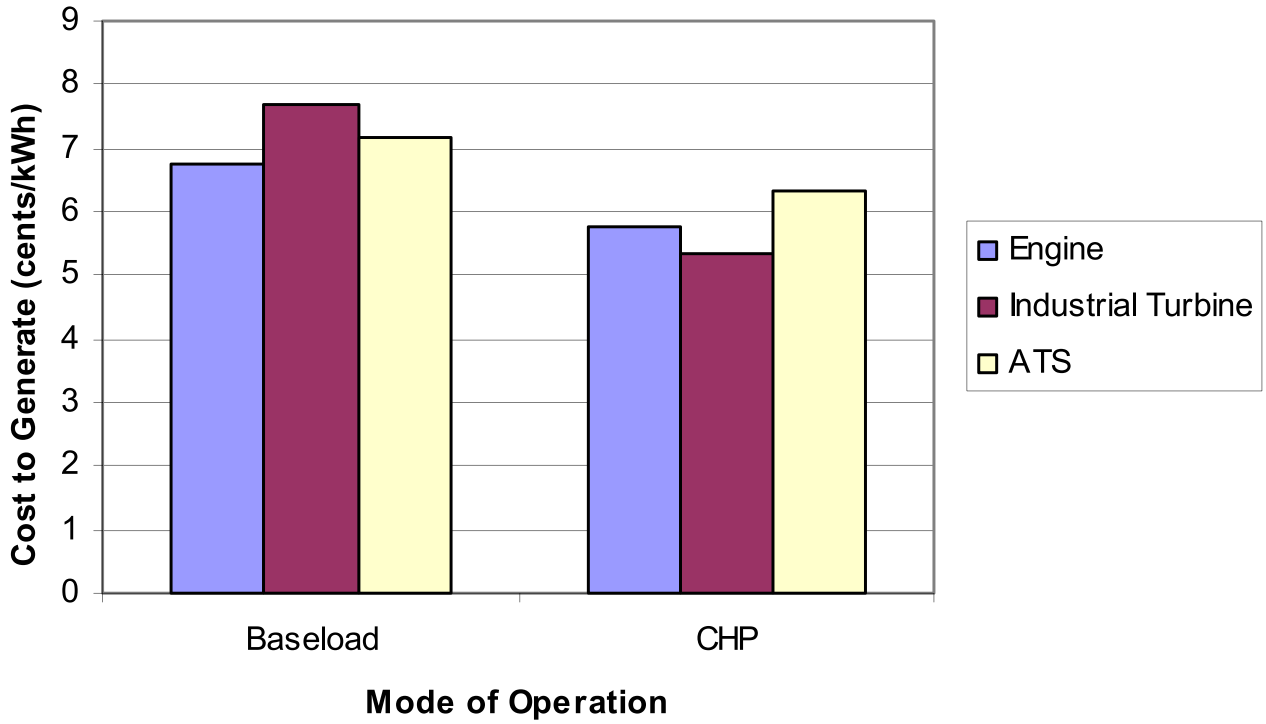


Figure 3-3. Cost-to-Generate Electricity by Technology (Cents/kWh)

Total Market Potential and Market Penetration

In the study, analysis was conducted to estimate the market potential for CHP technology when used to provide power generation without heat recovery, traditional CHP, CHP with absorption cooling, and engine-driven chillers (EDC) for process cooling. As shown in Figure 3-4, the market potential for these applications in the U.S. industrial sector is estimated at 33 GW of power generating capacity with currently available technology.

In Figure 3-4, market estimates of CHP potential show that almost three-quarters (about 24 GW) of the current market potential is for straight CHP applications, where the waste heat from power generation is captured and used as hot water or steam for process heating. CHP with absorption represents a sizeable 15 % of the potential (about 5 GW), serving industries with substantial cooling demand, including the chemical and petroleum industries.

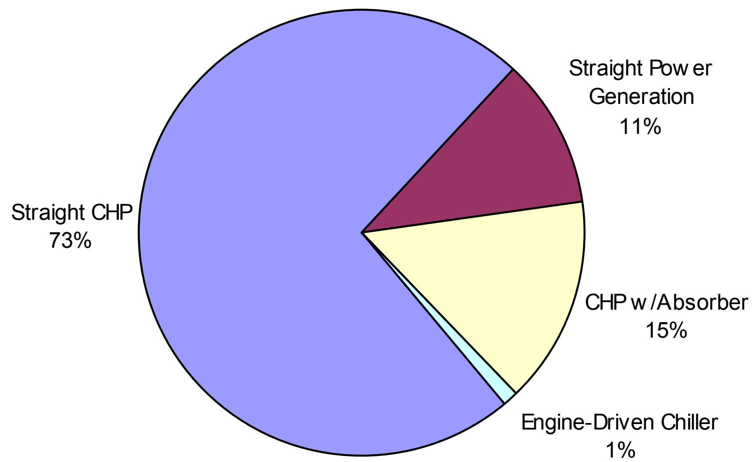


Figure 3-4. U. S. Industrial CHP Market Potential with Current Technology (33 GW)

The market for straight power generation is not insignificant, mostly for larger industrial facilities that can accommodate larger (20-50 MW) combined cycle units with relatively low cost of generation. These applications are strong in California, with its high grid prices, and for large primary metals facilities with relatively low steam/hot water demands. There is little potential for engine-driven chillers when based on their power generating capacity, but they represent over a third of the CHP cooling capacity on a tonnage basis in this analysis. The details of the analysis will provide some insight into this market breakdown when aspects such as the type of unit, regional characteristics, and industry needs are considered. These details follow.

The focus of this effort was to determine the market potential for CHP in the industrial sector. Over time, provided economic conditions prevail or become even more favorable and CHP technology proves its worth, it will realize a growing portion of this potential. This adoption of a technology is referred to as market penetration, and the rate of penetration depends on a number of factors. In this instance, these factors include cost and performance of CHP units and competing energy market economics (i.e. purchasing from the grid), as well as competition within the industrial facility from other capital investments. Other factors that could contribute significantly to CHP market penetration are the age of existing equipment and the financial health of the industry.

Based on data from the Energy Information Administration (EIA), it is estimated that current CHP use in the industrial sector for units up to 50 MW is about 11 GW[1]. Comparing this value with the market potential estimate of 33 GW, it would appear that the market penetration is about one-third. While there is little data on penetration rates of new CHP technology under the current economic conditions, the industrial decision making process regarding energy-related investments in general can yield some insights.

Many studies on the acceptance of energy-saving investments examine the amount of time necessary to payback the investment. While the market potential presented here is based on a ten-year cash flow analysis to determine the option with the best net present value, a simple payback was also calculated. Figure 3-5 illustrates for the current case that almost 20 % of the applications offer a payback under 2 years, and almost 60 % (about 20 GW) of those deemed economically feasible have a payback under 4 years. Assuming that the 11 GW that has been installed was taken from the more attractive paybacks, that means that about 9 GW of under 4 year payback market potential is still unrealized. This portion is likely impeded by market or regulatory barriers discussed in Section 4 of this report.

With the general rule of thumb that a 2-4 year payback is required for industrial facilities to purchase equipment that will reduce their energy bill[2], With 9 GW of applications offering paybacks in this range that have not been installed, the indication is that further cost reductions or economic assistance (e.g. tax incentives or rebates) may be required to stimulate this attractive but unrealized portion of the market.

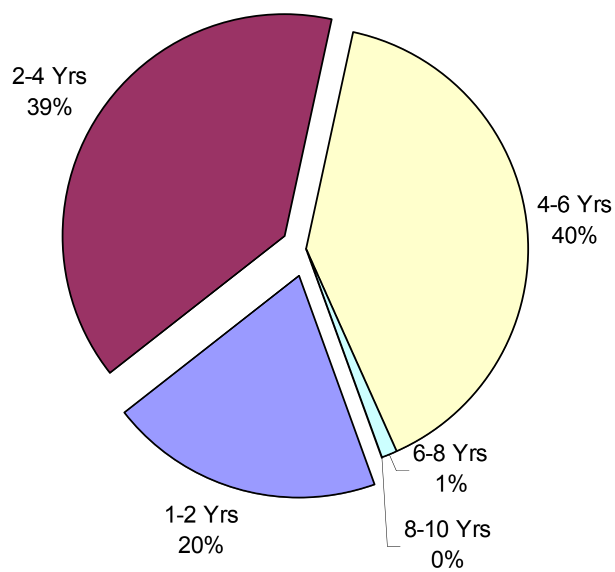


Figure 3-5. Distribution of Payback Periods for Potential Industrial CHP Applications

[1] Energy Information Administration, Form 860B, 1999.
[2] Department of Energy, Industrial Assessment Database, Office of Policy and Office of Energy Efficiency and Renewable Energy, March 1996.

Incorporating the cost of CHP units as well as their impact on customer energy bills over a ten-year period, the analysis provided the net present value of market potential by region. As shown in Figure 3-6, CHP offers almost $20 billion in net present value to industrial facilities in the U.S. As discussed, some of this value has already been realized by applications that have been installed, but a significant portion still remains. While turbines and engines lead the way for currently available technologies, as cost and performance of fuel cells and combined cycle units improve, the potential value to industry will continue to grow. These savings would translate to improved competitiveness of global markets, as well as potential for increased employment and other national economic benefits.

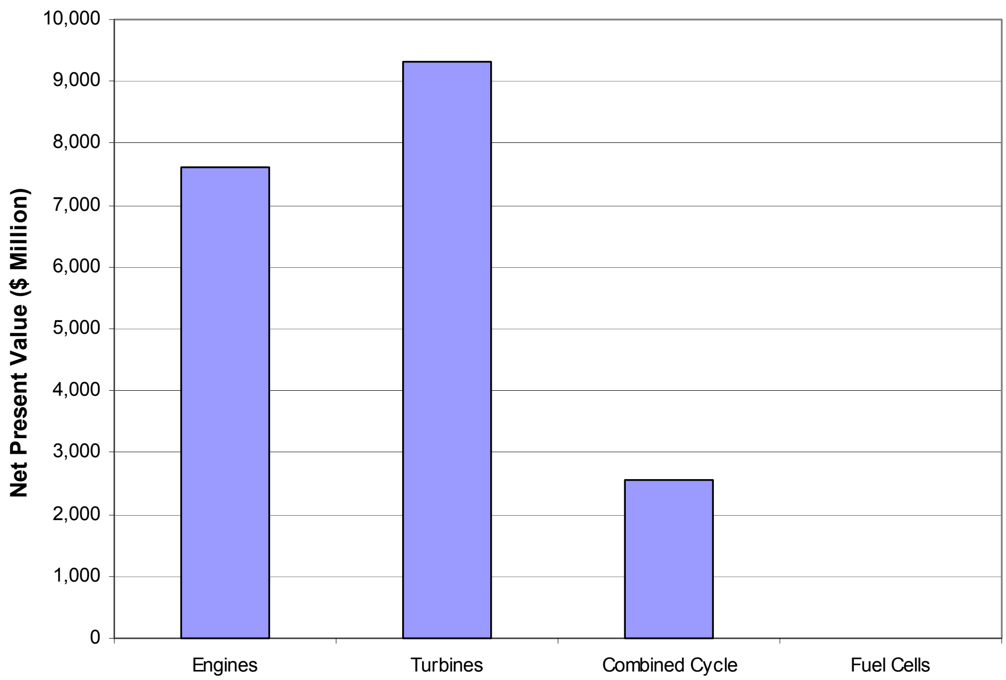


Figure 3-6. Net Present Value of Savings from Industrial CHP Market Potential (Million $)

Market Potential by Technology and Unit Size

Figure 3-7 illustrates the projected industrial market potential by CHP technology. The market analysis shows that in the base case, the CHP marketplace is shared by turbines and reciprocating engines. In the future, turbines adopt many of the high efficiency features pioneered by ATS turbines, and thus are projected to take CHP market share from engines, ATS systems, and even combined cycles. In the future scenario, overall market potential improves as well, almost reaching 50 GW. Although not shown on the figure, in the future fuel cells are projected to drop below $1,500/kW installed with the development of molten carbonate and solid oxide technologies, and emerge in the future CHP marketplace with less than 5 MW of capacity. This penetration could become more widespread if installed costs below $1,500/kW are attained.

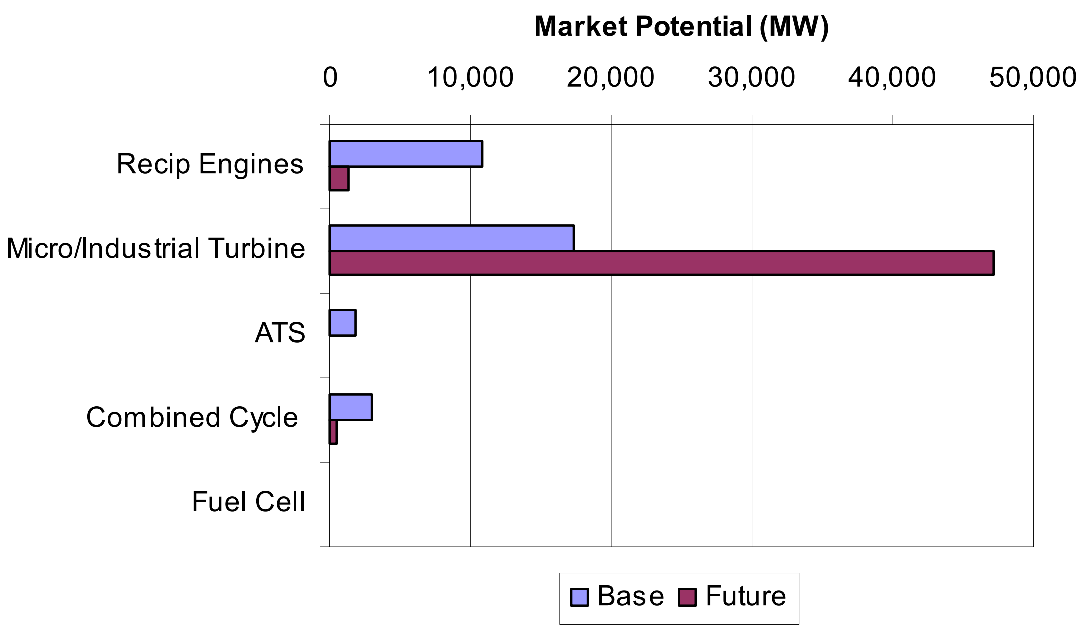
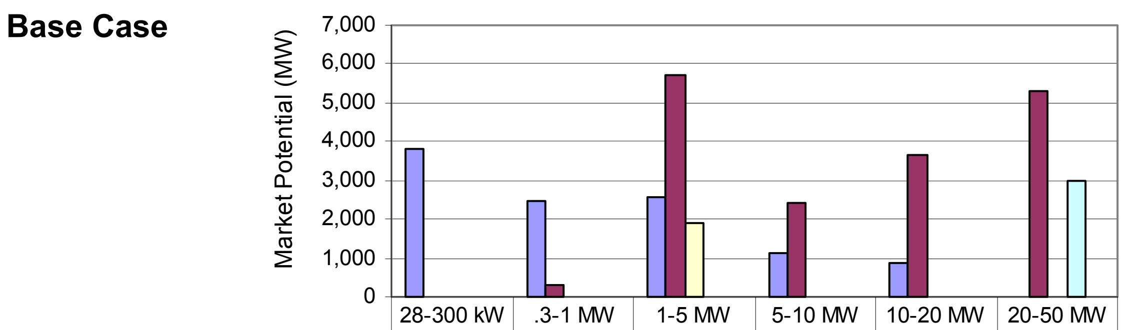


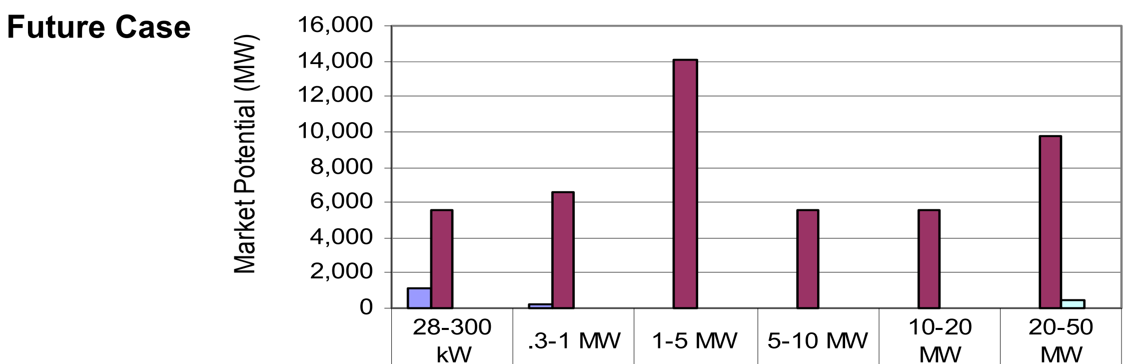
Figure 3-7. Industrial Market Potential by Technology (MW)

Figure 3-8 shows how the market potential of CHP technology varies by the size of the generating unit. In the base case, engines dominate in the smaller sizes (under 1 MW) over microturbines and fuel cells. Their combination of high efficiencies and competitive installed cost makes engines hard to beat. In the mid range (1-20 MW), turbines take over, due to the large concentration of CHP compatible sites in this size range. Turbines offer better economics for CHP when most or all of the thermal output is valued. In the larger sizes (20-50 MW), turbines continue to do well for CHP applications, and combined cycle units emerge in the 20-50 MW size for some CHP and some baseload power applications.

In the future, the turbine market potential greatly expands as microturbines take over in the under 1 MW CHP applications, and mid range and larger turbines benefit from improved electrical efficiency as ATS features are incorporated into conventional turbine products.



	28-300 kW	.3-1 MW	1-5 MW	5-10 MW	10-20 MW	20-50 MW
Recip Engines	3,790	2,490	2,570	1,150	880	0
Micro/Industrial Turbines	10	300	5,720	2,400	3,660	5,280
ATS	0	0	1,880	0	0	0
Combined Cycle Units	0	0	0	0	0	3,010
Fuel Cells	0	0	0	0	0	0

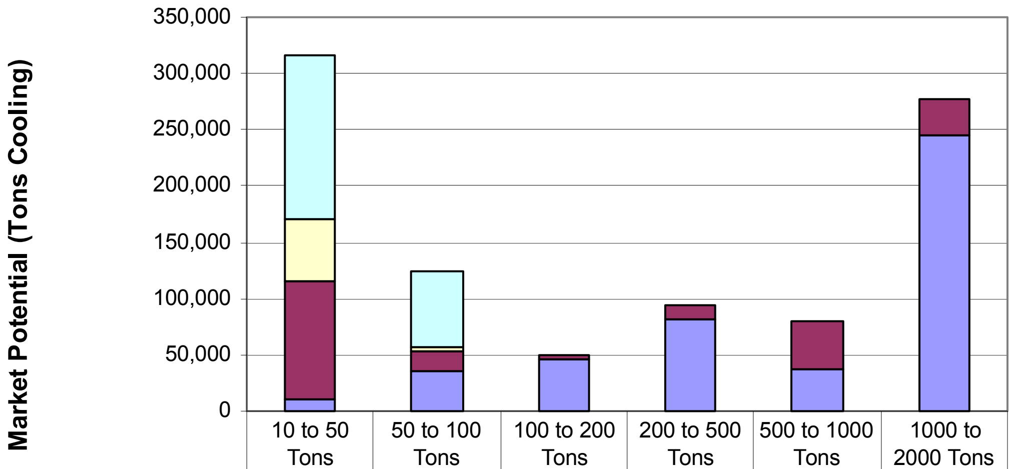


	28-300 kW	.3-1 MW	1-5 MW	5-10 MW	10-20 MW	20-50 MW
Recip Engines	1,120	220	10	0	0	0
Micro/Industrial Turbines	5,530	6,630	14,110	5,520	5,550	9,810
Combined Cycle Units	0	0	0	0	0	430
Fuel Cells	2	0	0	0	0	0

Figure 3-8. Industrial CHP Market Potential by Unit Size

Furthermore, as previously mentioned, about 15 % of the potential applications of CHP favored the generation of cooling from the CHP unit. Four different cooling operating strategies were explored, including single effect absorption units and engine-driven chillers, either baseloaded or serving the entire cooling load. The market potential, in terms of cooling tons, is shown in Figure 3-9 for each of these four strategies.

Figure 3-9 shows that Engine-Driven Chillers (EDCs) are very competitive in the smaller size ranges, particularly for serving the entire cooling load (sized to peak). In the 10-50 Ton range, EDCs sized to peak offer the potential for over 140,000 Tons of cooling. Peak-sized absorbers also do well in this smaller range, representing over 100,000 Tons of potential cooling. A similar but lower potential is demonstrated in the 50-100 Ton range, and as the on-site cooling load grows, the potential for baseload absorbers takes hold. This technology and operating strategy leads the remainder of the cooling size ranges, topped off by the 1,000-2,000 Ton range, where baseload absorbers show most of their potential. In this size, the capital cost of absorbers drops significantly, and the economics improve as a result.



	10 to 50 Tons	50 to 100 Tons	100 to 200 Tons	200 to 500 Tons	500 to 1000 Tons	1000 to 2000 Tons
EDC Peak	144,700	67,500	1,200	200	0	0
EDC Baseload	56,300	3,300	0	0	0	0
Absorber Peak	104,100	18,100	3,800	11,600	42,100	32,700
Absorber Baseload	10,700	34,700	45,500	82,200	37,600	245,200

Figure 3-9. Industrial CHP Cooling Market Potential by Range of Cooling Unit Size

Market Potential by Region and Industry

Not surprisingly, industrial CHP potential tends to be strongest in areas with relatively high electricity prices and concentrations of industrial sites. As shown in Figure 3-10, current CHP potential is concentrated in the Pacific (led by sites in the Southern California Edison and PG&E service areas), East North Central (led by sites in the ComEd and Detroit Edison service areas), Mid Atlantic (led by sites in the Niagara Mohawk, PECO Energy, and PSE&G service areas), and South Atlantic (led by sites in the Georgia Power, Carolina Power & Light, and Duke Energy service areas) regions.

If CHP technologies improve as projected in the Future Case, several regions of the U.S. stand to benefit as CHP potential grows regionally. This growth occurs mostly in the South Atlantic Atlantic (led again by sites in the Georgia Power, Carolina Power & Light, and Duke Energy service areas) and East North Central (led again by sites in ComEd and Detroit Edison's service area), with some notable expansion in the West South Central region (led by sites in the Houston Lighting and Power and TU Electric service areas). In the Future Case, CHP potential will no longer be concentrated in the Pacific and East Coast regions. Much of this effect is due to the technologies improving their cost and performance, thus not requiring retail electricity prices to be as high for the economics to be favorable.

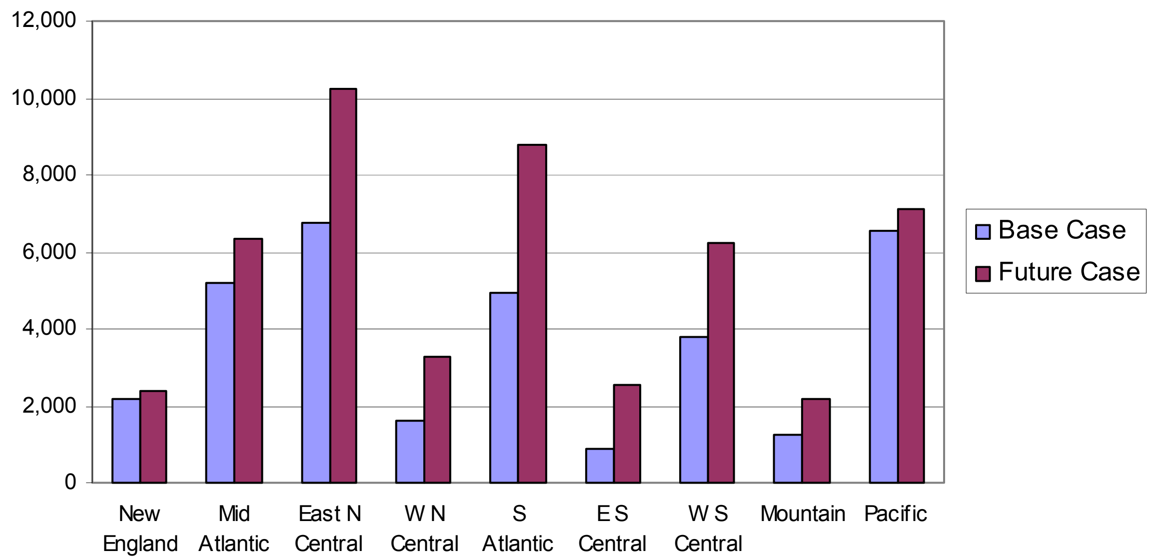


Figure 3-10. Industrial CHP Market Potential by Region (MW)

Figure 3-11 illustrates the top industries that offer CHP and CHP cooling market potential. The CHP potential is led by Chemicals (SIC 28), Primary Metals (SIC 33), Paper (SIC 26), and Food (SIC 20). Together, these four industries represent over half of the market potential. This is not surprising when it is considered that these industries account for over half of manufacturing electricity, boiler energy, and total energy consumption.

High thermal-to-electric ratios are often cited as an indicator of strong CHP potential. In particular, the ratio of boiler energy to electrical energy is critical, since the thermal output from CHP systems generally supplant boiler thermal output (steam or hot water). Some applications use the output of a turbine directly in a process to supplant direct process heating (such as using turbine exhaust to heat a dryer for clay products), but these are generally thought of as niche applications. Three industries, Food, Paper, and Chemicals offer some of the strongest boiler to electric energy ratios, calculated at 2.8, 3.8, and 2.4 respectively. These are considerably higher than the manufacturing average of 1.4.

The Primary Metals industry offers a very low boiler to electric energy ratio (0.3), and accounts for the second largest potential (4.4 GW in the base case) due to baseload power generation with large combined cycle units as well as some CHP with large turbines. In these applications, the cost to generate is very low, and competitive with the grid even with fairly low thermal utilization.

The CHP cooling market potential is led by the Electronics industry (SIC 36), followed by Chemicals (SIC 28), Petroleum (SIC 29), and Food (SIC 20). As shown in Table 3-1, these four industries account for over two-thirds of the current cooling capacity as well as the potential for CHP-driven absorbers. The Electronics and Petroleum industries have relatively low estimated installed bases of cooling, and thus are somewhat surprising in their potential for CHP cooling. Their potential, however, is driven largely by favorable CHP economics coupled with relatively low steam/hot water demands, which leaves cooling as the leading viable use of the CHP waste heat. Indeed, CHP cooling constitutes over 95 % of the CHP market potential in the Petroleum sector, and is almost 50 % in the Electronics industry (compared with only 15 % for all manufacturing). Comparing the potential CHP cooling tons with the estimated installed cooling capacity, these two industries each show that the potential CHP cooling is a third or more of the installed cooling base, compared with Food and Chemicals, where the potential is a much smaller share of the installed cooling capacity.

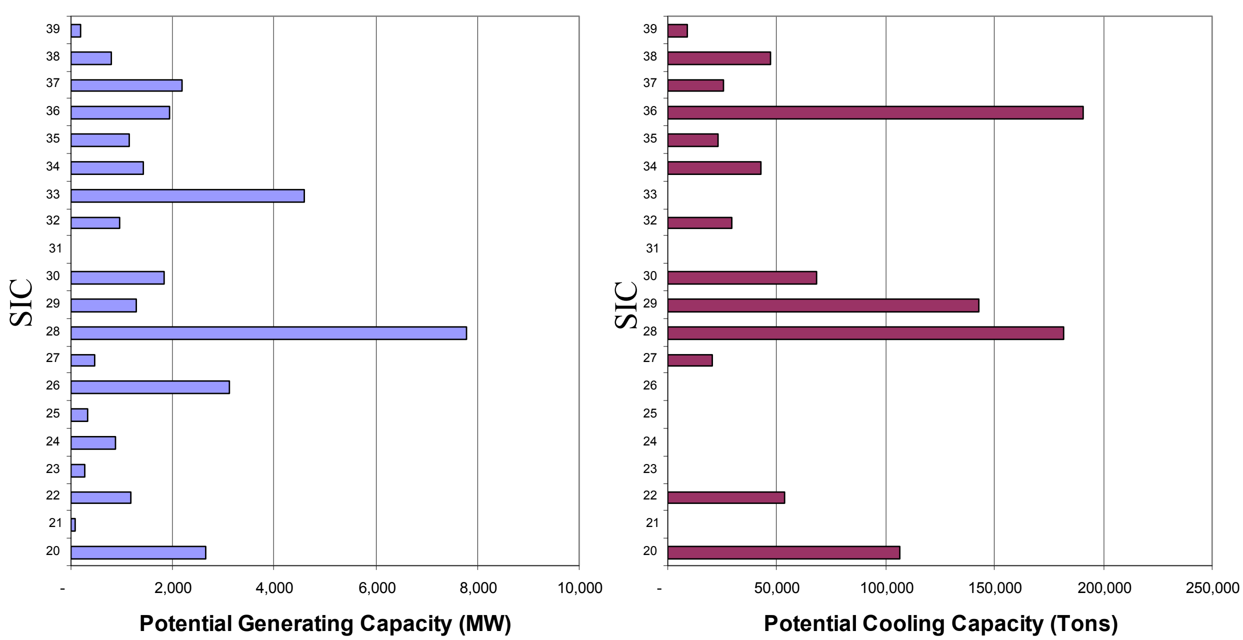


Figure 3-11. Industrial CHP Market Potential by Industry SIC (MW)

Table 3-1. Comparison of Estimated Installed Cooling Capacity vs. CHP Cooling Potential

Industry (SIC)	Cooling Energy Consumed (Trillion BTU)		Estimated Installed Cooling Capacity (1,000 Tons)			CHP Absorber Potential (1,000 Tons)	CHP Absorber Potential Share of Total Capacity	Current Gas Cooling Share of Potential Gas Cooling
	Electric	Gas	Electric	Gas	Total			
Food (20)	48	1	3,300	13	3,313	106	3%	12%
Chemicals (28)	32	11	2,200	143	2,343	182	8%	79%
Petroleum (29)	6	3	400	39	439	143	33%	27%
Electronics (36)	7	0.3	500	4	504	191	38%	2%
All Mfg	138	21	9,600	273	9,873	941	10%	29%

Notes: Thermal cooling estimated for SIC 29 (value withheld). Conversion to tonnage based on centrifugal chiller at .6 kW/Ton for electric cooling, and on double effect absorber at 11,000 BTU/Ton. Assumes 7,000 hrs per year operation for conversion to Tons. Source: EIA Manufacturing Energy Consumption Survey (MECS) 1994, and Resource Dynamics Corporation estimates.

Sensitivity Analysis

A number of scenarios were constructed to evaluate how sensitive the base case is to varying inputs. The scenarios focused on how improving the cost and/or the efficiency of CHP impacts the market size. Three scenarios were added to illustrate the effects of changing energy prices on the CHP market for industrial applications. As shown in Table 3-2, a total of 5 scenarios were analyzed.

The first two involved current (2000/2001) energy prices, with either current (2000/2001) unit cost and performance or anticipated future changes in unit cost and performance (2005+), and are documented in Tables A-1 and A-2 in Appendix A.

Table 3-2. Scenarios Depicted by Sensitivity Analyses

Scenario	CHP Cost and Performance	Energy Prices
1. Base Case	Current	Current
2. Future	Future	Current
3. Moderate FAC	Current	Moderate Prices with Fuel Adjustment Clause
4. High FAC	Current	High Prices with Fuel Adjustment Clause
5. Peak FAC	Current	Peak Prices with Fuel Adjustment Clause

The second three scenarios involved changing energy prices. As shown in Figure 3-12, natural gas prices increased dramatically in late 2000 and through 2001. This increase was not reflected in the base case gas prices. Industry experts forecast a range of expectations of future gas prices, with some calling for high prices to last a couple of years and others predicting long term impacts.

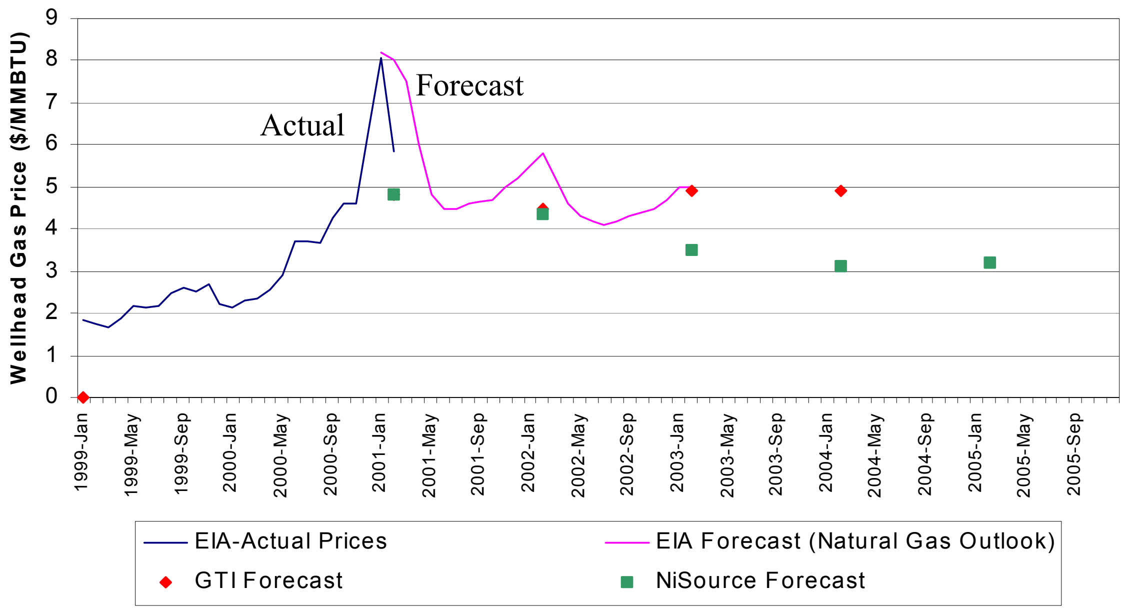


Figure 3-12. Natural Gas Price Increase (Through March 2001) and Industry Forecasts

As a result, two alternative gas price scenarios were developed: 1) moderate prices (Moderate FAC), which calls for wholesale natural gas prices to hover around $5/MMBTU for 2001-2002 then falling to $3-4/MMBTU, and 2) high prices (High FAC), which call for the $5/MMBTU wholesale prices to persist for the ten years up to 2010. Figure A-3 in Appendix A provides an example of the Pacific Census Region, illustrating these scenarios for industrial gas prices (as stated earlier, industrial prices are used to approximate the rate that would be paid by a facility utilizing natural gas cooling or combined heat and power, and are typically lower than small commercial rates but higher than prices utilities pay). These scenarios were not adopted as expectation of future prices, but simply to examine the impact on the CHP market in buildings should either scenario emerge.

Since it is generally accepted that there is convergence in gas and electric prices, translating the effect of high natural gas prices on industrial electric rates was important in analyzing these scenarios. A methodology was developed to estimate the increase in fuel costs and allocate that cost to the electricity generated to derive an updated electricity price. This method is similar to how utilities calculate their fuel adjustment clause.

A final price scenario (Peak FAC) was added to see how the industrial market for CHP would be affected if the increase in gas prices was reflected solely as a demand-based charge. While this value would ultimately likely be embodied in only the limited number of peak pricing hours (e.g. the 200 highest-priced hours), it was difficult to do so for this analysis. The increase in gas prices paid by generators was divided by the peak demand, and thus a $/kWcharge was calculated. This value ranged from over $50/kW annually ($4/kW per month) for parts of Texas down to less than $1/kW annually for a number of areas including Kentucky and other parts of the nation with low shares of natural gas-fired generation.

Overall market potential results of the sensitivity analysis (see Figure 3-13) indicate that improvement in the installed cost and efficiency increases the market size dramatically. The Future Case increases the potential market from 33 to almost 50 GW, about a 50 % jump in the market size. The results show that the major increase is primarily due to realizing the improvement in cost, and to some degree efficiency, that is expected in the future scenario.

The price sensitivities tell another story. In general, it appears that higher energy prices lead to less potential for CHP in industry. Figure 3-14 illustrates that this holds on a regional basis, with every region in the U. S. showing a decrease in market potential from the Base Case as energy prices rise. The majority of new capacity – either planned or under construction – is expected to be fueled by natural gas, which would create more convergence in gas and electric prices, and thus diminish the negative effect of higher gas prices on CHP.

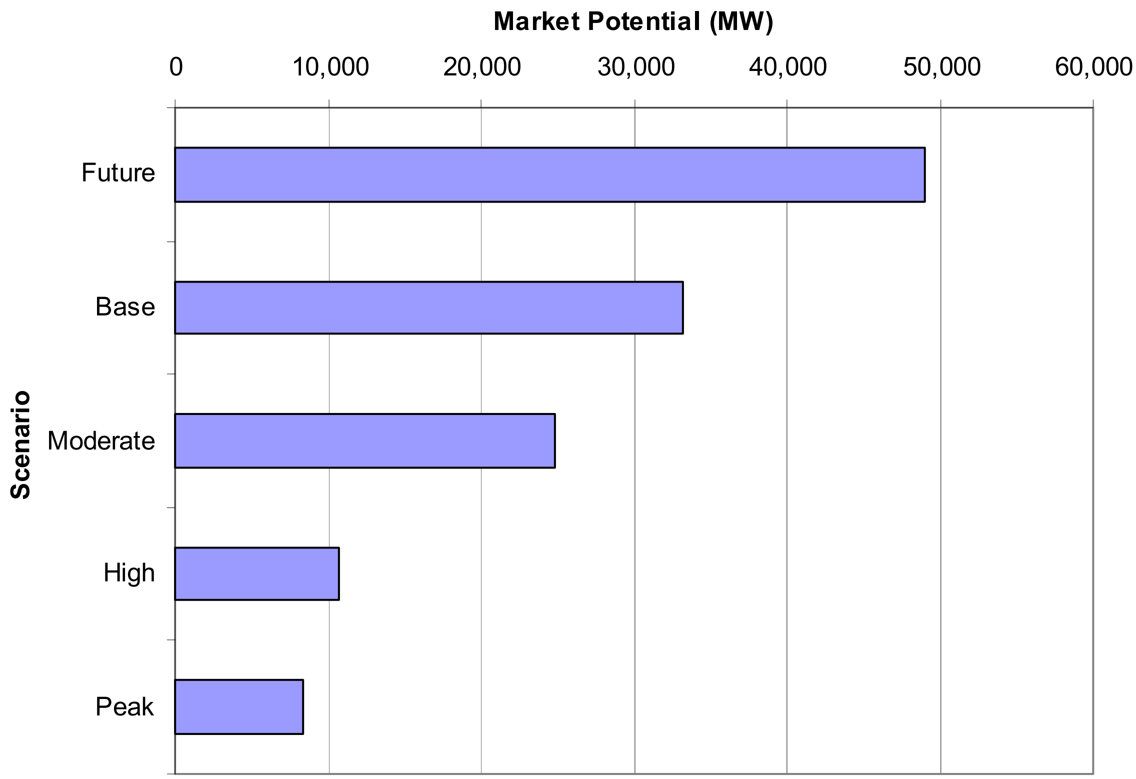


Figure 3-13. Future Scenario Offers Highest Market Potential

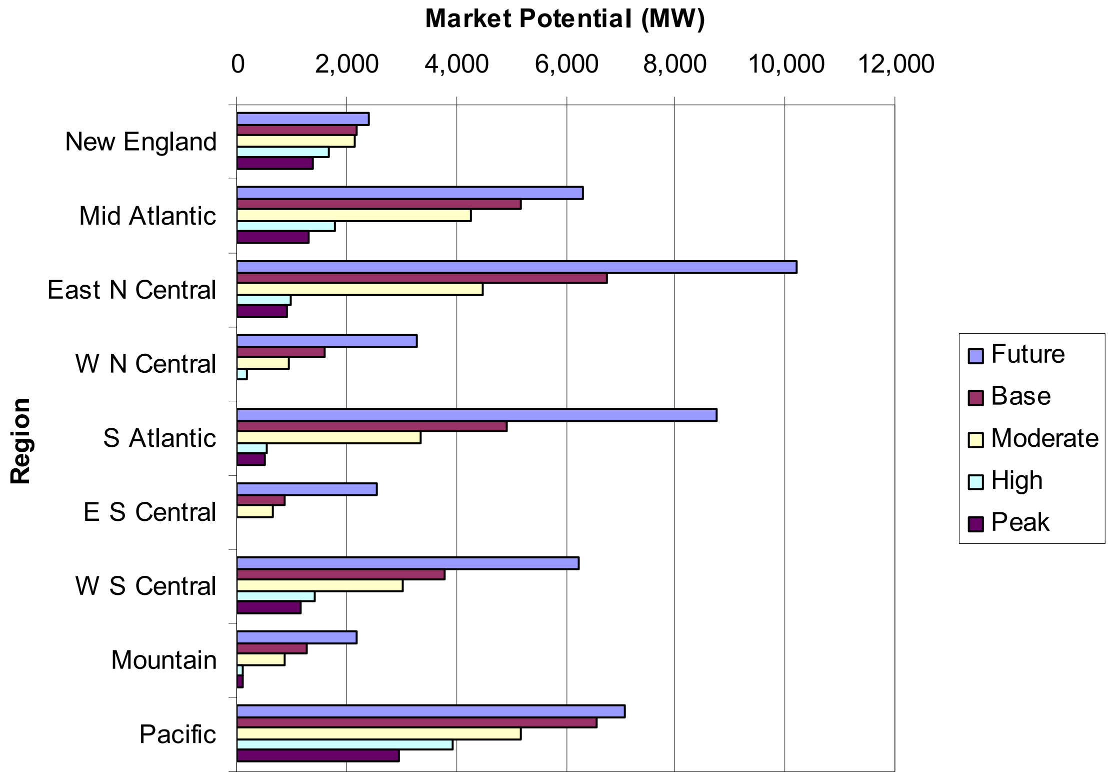


Figure 3-14. Regional Effects of Price Sensitivities on CHP in Industry (MW)

Section 4

TECHNICAL AND MARKET BARRIERS

Despite improving economics, concerns over restructuring of the electric utility industry, a large number of success stories, and a sizeable installed base, CHP systems still face a battle in the industrial market. Realizing the benefits inherent in implementing CHP on a wider scale continues to be hindered by a combination of barriers in the following categories:

- Economics and tax treatment,
- Product performance and availability,
- Awareness, information and education,
- Utility policies and regulation[1],
- Planning, zoning and codes,
- Environmental regulation, and
- Supporting market infrastructure.

These barriers can often make a CHP project uneconomic, and can frequently present such a confused and uncertain option to potential end users that the more traditional purchased power approach is favored. Table 4-1 identifies examples of each of the barrier categories.

Table 4-1. Market and Technical Barriers to Industrial CHP with Cooling

Category	Example Constraint
Economics and Tax Treatment	Lack of available tax credit to help defray capital cost; treatment as 15 year property under current tax laws.
Product Performance and Availability	Lack of systems that integrate heat recovery for process heating and/or cooling.
Awareness, Information and Education	Limited understanding of range of benefits associated with CHP systems and thermally-driven cooling technologies.
Utility Policies and Regulation	Costly grid interconnection requirements; "transition charges" or "exit fees".
Planning, Zoning and Codes	Local requirements for operator licensing and 24 hour supervision, resulting in delay/increased costs for many small CHP projects.
Environmental Regulations	Lack of recognition and credit for overall efficiency in determining compliance with Clean Air Act requirements: drawn out siting and permitting procedures at state and local level (24 months or longer).
Supporting Market Infrastructure	Sales force of absorber manufacturers may still emphasize electric chillers.

A number of forces are driving a renewed industrial sector interest in CHP technologies. Electric industry restructuring is opening the door to new business arrangements and non-traditional energy suppliers, and customers in increasing numbers are taking the lead in meeting their

[1] For a compendium of cases where interconnection barriers affected distributed generation projects, the reader should consult the Making Connections: Case Studies of Interconnection Barriers and their Impact of Distributed Power Projects, published by the National Renewable Energy Laboratory, NREL/SR-200-28053, May 2000.

ultimate energy requirements. The pace of this change, and the degree to which the benefits of CHP are realized, depend on the ability of all stakeholders to overcome these barriers. Each category of barriers is discussed in detail below.

Economics and Tax Treatment

Many plant managers and engineers make decisions on the basis of first cost, and CHP options tend to cost more than conventional alternatives. As a result, many industrial facilities do not include CHP systems even when life-cycle economics are favorable. Therefore, first cost remains a large barrier. One trend that is emerging to overcome this barrier is the willingness of third parties to invest in CHP systems. A number of utility subsidiaries, along with industry leaders such as Trigen Energy, are proactively searching for such investment opportunities, and providing plant managers with many of the economic benefits of CHP systems without requiring the upfront capital premium. Furthermore, aggressive leasing companies are offering leasing options that allow plant managers to effectively purchase CHP systems without any capital outlay. Such leasing options are widely accessible to industrial firms.

Additional assistance in overcoming this barrier could be provided by the availability of a tax credit for selected CHP equipment to help defray project capital cost. Tax treatment of CHP systems varies considerably based on asset use and generating capacity (see Table 4-2). Other means of lessening the unfavorable tax treatment could be shortening the asset life or allowing for accelerated depreciation.

Table 4-2. Tax Treatment of CHP Property

For Customer Use	>500kW		<500kW	
	Cost Recovery Period	Depreciation	Cost Recovery Period	Depreciation
	15 yrs	150% Declining Balance	5-10 yrs	200% Declining Balance
For Sale to Others	Separate Project		Part of Structural Components of Non-Residential Building	
	Cost Recovery Period	Depreciation	Cost Recovery Period	Depreciation
	15 or 20 yrs	150% Declining Balance	39 yrs	Straight Line

Product Performance and Availability

While CHP systems have been available for years in sizes that apply to industrial facilities, the performance and availability of thermal-driven cooling technologies has been a barrier to widespread application of these technologies in stand-alone configurations, much less as a component in a CHP system.

While the absorption chiller technology has been around since the late 1800s, historically the manufacturing base for these units was largely in Japan. Japan developed these units to help reduce dependency on high cost imported fuels, and recognized the benefits of higher efficiency levels that could be attained. During this period, however, availability and lead time for U.S. orders lagged behind that of conventional electric chillers, and thus only a small niche market emerged. In the 1990s, however, several of the largest U. S. manufacturers of electric chillers developed offerings, and were able to reduce costs and lead times and improve availability. As a result, the market for absorption chillers has been growing. There is still considerable resistance, however, in the plant engineering community to consider these units as viable options to compete with electric chillers.

Similar resistance confronts engine driven chillers (EDCs). EDCs, despite being constructed of proven components, still are seen as an emerging technology and are not always considered as a viable option, even when the prevailing gas and electric rates favor their use. A major consideration with these units is the frequency of maintenance, which is higher than for electric chillers. Even with reputable contractors capable and available to perform required servicing, maintenance remains a barrier to more widespread adoption. EDCs are, however, making headway in markets where their economics are strong.

The lack of technology maturation contributes to the underlying uncertainty in the ability of microturbines and fuel cells to meet cost and performance targets. This presents an obstacle to aggressive implementation of these technologies.

Maintenance practices for microturbines are still being developed as field experience grows. Maintenance cycles are being recommended by manufacturers, but are not yet proven in operating practice, and synchronization of maintenance requirements for the turbine components and the gas compressor has been an issue. Lack of standardized maintenance practices and confidence in longer-term maintenance costs may tend to delay application of these technologies, although manufacturers are offering maintenance contracts to help allay these concerns.

There are a number of technical challenges in fuel cell technology that need to be overcome in order to gain market acceptance. The energy cells are stacked together in series to provide the needed power output. Results to date indicate that fuel cell power output degrades over time, requiring periodic stack replacement during the unit’s lifetime. The short stack-lives lead to life-cycle costs that make the resulting power output noncompetitive with grid-purchased power in most parts of the country. The emerging solid oxide and molten carbonate fuel cells may help minimize this constraint.

Awareness, Information and Education

The plant management community tends to be risk adverse, favoring the “tried and true” alternatives and not recommending options that they have not specified before. Frequently following the path of least resistance, plant managers and engineers will often stay with grid purchased power, typically not realizing the full value of the CHP benefits. Further exacerbating this situation, and contributing to rather than breaking down the cost barrier, is the industrial sector's frequent focus on capital cost versus life-cycle cost. While some industries have embraced CHP more than others, risk adverse behavior still has a negative impact on CHP use.

As more success stories of how CHP is being used by manufacturing firms around the country emerge, the awareness and education barrier should continue to be lowered. In addition, having energy service companies and firms who specialize in CHP promoting turnkey applications, the risk is shifted away from the plant management community and thus minimizing the negative impact of risk adverse decision making process.

Utility Policies and Regulation

Many utilities have instituted backup power rates that add substantial costs to CHP applications. While these rates may or may not accurately reflect the higher cost of "reserving" capacity for these part-time customers, they act as a barrier to implementation of CHP for both commercial and industrial applications.

Interconnection is another critical issue, with utilities often requiring protective relaying on the utility side of the meter to ensure that the grid is protected from any problems caused by the distributed generator. In many cases, the utility has not accepted the protection functions provided by the electronic interface package included with many microturbines and fuel cell systems, a package providing many, if not all, of the utility-required protective relaying functions. This duplication of interconnection requirements raises the costs to the industrial facility, with interconnection costing as much as 15 to 20 percent of the installed cost of the on-site generation package. The IEEE is developing a standard for interconnection of small power systems with the grid, which should help reduce the costs and uncertainty of interconnection requirements for smaller industrial sites that adopt CHP.

As electric industry restructuring begins to make its way across the country, industrial facilities that choose to leave the grid of the local energy supplier are required to pay "transition charges" or "exit fees" designed to help the local utility recover investments in "stranded" generation or transmission assets no longer producing revenue for the utility. Burdening the industrial facility with these exit fees and competitive transition charges is a disincentive to CHP project implementation. While there are issues regarding the legitimacy of these costs, such as new CHP owners claiming they had notified the utility far in advance of their intent to install CHP, there are real costs to the utility and other ratepayers should not be required to subsidize CHP. The fees for exiting the grid during the transition period should, however, be fair to other ratepayers but not unfair to users who wish to generate their own power.

Planning, Siting and Zoning

CHP systems are and will be affected by local zoning policies, building codes and standards, and other issues including union labor and 24-hour attended operation. For example, microturbines require natural gas input at 55 to 85 psig, compared to the typical gas distribution system pressure of 1 to 50 psig. Accordingly, a gas compressor is frequently required as part of project initiation. If this unit is located within the facility, local codes may require 24-hour attended operation for a pressure vessel of this rating. Many of the microturbine installations are expected to be outdoors, which may mitigate this constraint. Union labor can vary considerably in location: one project developer cited projects in California being much more expensive than similar projects in New Mexico, mostly due to differences in union labor rates.

While many of the local codes and zoning requirements may not result in additional equipment or operating costs, the process of determining what the requirements are is often not clear to the local jurisdiction, and it will require time to get necessary approvals. Delays due to this process can be quite frustrating to plant managers, and may lead to abandonment of CHP projects. These issues tend to be more of a barrier to smaller projects than to larger (above 5 MW) sites. Having project developers experienced in both CHP systems and working with the local contractors can be a big plus in terms of getting the project done.

Environmental Regulation

CHP projects typically experience drawn out siting and permitting procedures at the state and local level which can stretch to 18 to 24 months or longer. Streamlined siting and permitting procedures would provide a major boost to CHP technology penetration.

Additionally, these projects do not currently receive credit for overall efficiency in determination of compliance with Clean Air Act requirements. Output-based emission factors accounting for overall fuel utilization efficiency would recognize the inherent efficiency advantage of power generation technology located close to the load, eliminating T&D lines losses, and taking advantage of CHP applications. Recent EPA guidelines for output based standards would help CHP units immeasurably, but it remains to be seen how states act on these guidelines in their State Implementation Plans (SIPs).

Many project developers see the control technology standards as a moving target. Even less strict areas where Best Available Control Technology (BACT) or even Reasonably Available Control Technology (RACT) are generally applied are seeing more requirements for the most expensive control technology options generally reserved for strict areas where the Lowest Achievable Emissions Reduction (LAER) is enforced. For engines, this often means expensive Selective Catalytic Reduction (SCR), and for turbines this often calls for SCR combined with Dry Low NO_x, or even in some areas developing technologies such as $SCONO_x$. When confronted by such expensive add-on control technology requirements, few CHP projects move forward.

“Green” power generation technologies are approved for use in a non-attainment area under current environmental regulations. Most CHP technologies do not qualify as “green” under today’s definitions. Broadening the “green” renewables standard to encompass an overall efficiency standard would offer expanded market reach to non-renewable CHP options.

Supporting Market Infrastructure

Both reciprocating engines and combustion turbines have extensive dealer and service networks, with a ready supply of trained mechanics and spare parts on a nationwide (and even worldwide) basis. The widespread transportation and machinery applications of diesel engines have provided a foundation for the power generation applications of the reciprocating engine technology. For turbines, infrequent maintenance coupled with scheduled monitoring activities has proven effective in keeping units operating. Fuel cells and microturbines will need to establish similar infrastructures to achieve market penetration.

While the thermal-driven cooling technologies have adequate support infrastructures, absorption units face a challenge within their manufacturing organization's sales arm, as representatives find it easier to sell their proven electric chillers than the lesser known absorption units. This experience is consistent with the challenges faced by electric cooking equipment produced by leading gas cooking manufacturers, as the "tried and true" alternatives require less intensive sales efforts, and therefore representatives choose to follow the path of least resistance. As more consulting engineers and other design professionals gain experience with these options, an increase in requests for absorption units will likely boost sales, therefore raise the visibility of these products within their parent organizations. As the market grows, the sales efforts should intensify.

While integrating any of the power generation technologies into a CHP configuration is typically left to third parties, there is a host of proven project developers that have developed a business out of successful installations. The cost of engineering, however, remains high for smaller units and is a significant burden on the installed cost of these units.

One major challenge faced by smaller CHP applications is the lack of integrated systems. Finding the optimal CHP components that, when integrated, can meet the wide range of process heating, cooling, and electric loads is left up to the plant management and their supporting design professionals. Several manufacturer teams have initiated development of integrated CHP and absorption chiller packages with controls that together comprise a turnkey CHP package. These units are being designed for the buildings market for CHP, but offer potential benefits to industrial facilities as well. Until many competitively priced, integrated CHP packages are available, however, the smaller industrial facility market for CHP will continue to be underdeveloped.

Section 5

TECHNOLOGY R&D IMPLICATIONS

The results of this study show that if CHP and cooling technology improve as assumed in the future scenarios, the industrial market would grow substantially in size. For CHP to realize this potential, a number of technology improvements are needed in order for CHP to be competitive with conventional options. Achieving improvements such as increased electrical efficiency, reduced maintenance, greater reliability, and lower emissions – all at lower costs – will require substantial research and development aimed at all technologies involved as well as their integration.

Improving CHP Technology

Specific R&D needs differ by technology, and are dependent on the maturity of that technology. Overall, the assumptions for future (anticipated by 2005-2010) improvements in cost and performance are aggressive, and call for 20-30 percent decreases in installed cost and a 10-40 percent improvements in electrical efficiency. These projections (see Table 5-1 for summary and Table A-1 for detailed assumptions), however, are based largely on discussions with manufacturers and on implementing improvements that are on the drawing board or are already incorporated in larger models. It should be noted, however, that meeting these targets is not essential to expanding CHP market potential, as even modest cost reductions (i.e. 5-10 percent) will result in the market size growing larger.

Table 5-1. Future Cost and Efficiency Improvements in CHP Technology (Selected Size Ranges Only)

Size	Technology	Base ($/kW)			Future ($/kW)		
		Packaged Cost	Elec Eff	Installed Cost	Packaged Cost	Elec Eff	Installed Cost
150-300kW	Recip	510	33.5%	880	375	43.0%	640
	Microturbine	700	27.1%	1,075	475	40.0%	720
	Fuel Cell	4,500	39.6%	5,000	1,275	50.0%	1,555
300-600kW	Recip	490	35.0%	800	375	43.0%	605
	Microturbine	700	27.1%	1015	460	40.0%	675
	Fuel Cell	4,500	39.6%	4,800	1,275	50.0%	1,520
1-2.5MW	Recip	470	38.0%	700	370	45.0%	550
	Turbine	470	28.0%	700	360	40.0%	525
2.5-5MW	Recip	470	39.0%	620	350	45.0%	465
	Turbine	440	29.0%	590	330	40.0%	420

Reciprocating Engines

Most of the current reciprocating engine R&D, including that being undertaken by DOE's Advanced Reciprocating Engine Systems (ARES) program, is focused on increasing efficiency and lowering NO_x emissions. Most new applications are lean-burn which gives the advantages of increased efficiency and lower NO_x emissions but has the disadvantages of difficult ignition and inability to use three-way catalysts to further reduce emissions. Additional R&D is being pursued in the areas of improved models, sensors, and controls.

To facilitate proper ignition and combustion, a pre-combustion chamber or high-energy/precise ignition sources can be employed. Research is ongoing into how changes in the pre-combustion and combustion chamber design can influence air flow and combustion which in turn influence power, efficiency, and emissions. Additional research devoted to ignition sources such as lasers promises to achieve ideal combustion through the precise placement and timing of ignition.

Lean-burn engines cannot use three-way catalysts which are employed in rich-burn engines such as those of gasoline fueled automobiles to simultaneously remove CO, NO_x, and unburned hydrocarbons. Although all emissions are typically lower from the combustion chamber of a lean-burn engine, research on new types of catalytic emissions reduction is needed to achieve the lower emission levels needed to be more competitive with turbines.

Effective turbocharging is key to increasing Brake Mean Effective Pressure (BMEP) which leads to increased efficiency. Turbocharging is especially important for lean-burn engines, which require high air-to-fuel ratios. Effective turbocharged applications require efficient turbochargers and components that can withstand increased pressure ratios.

Additional research is being conducted on improved sensors and models to better understand the combustion process inside an engine and on better controls to effectively manipulate the combustion process on-line to achieve ideal combustion.

Microturbines

Microturbine development needs are focused on increasing efficiency, reducing costs, and providing fuel flexibility. In addition, the technology needs to be more extensively tested and demonstrated for the full range of commercial applications.

Efficiency improvements hinge upon developing effective recuperators. Recuperators use part of the exhaust from the microturbine to heat inlet air into the combustor. With recuperation, electric efficiencies have been increased to 26-30% from 15-22%. In order to approach the current targets of 40%, higher temperature turbine inlet air will be required, necessitating higher temperatures in the recuperator, combustion chamber, and turbine section. Withstanding the higher temperatures will require advances in temperature resistant materials (e.g. ceramics) for the recuperator, combustor, and turbine hot section. Another way to improve microturbine efficiency is to couple it with a fuel cell (usually solid-oxide). The future of these microturbine/fuel cell hybrids is dependent on fuel cell development as well as research into the best performing thermodynamic cycle to employ.

To reach cost targets of $400-600/kW, microturbine developers will need to focus on reducing the cost of the main unit as well as the packaging and support equipment. Most microturbines typically employ a single shaft which leads to simplicity and ease of mass production, both key to lower costs. However the single, high-speed shaft requires the use of an inverter/rectifier to provide standard AC power, and any reductions in the cost of this equipment, such as thyristors and inverters, would improve overall system economics. When microturbines are fueled by natural gas, as they are with current models, gas compression is often necessary to increase the pressure over what is typically available from the local gas main. Compressors of the size necessary for microturbines are not prevalent and can be costly (leading to higher capital costs as well as associated O&M expense). Research into reproducing the characteristics of larger compressors for smaller units will be a key to the success of microturbines.

Fuel Cells

Fuel cells are an emerging technology with currently only one manufacturer offering commercial units. As such, most of the research and development issues for fuel cells are centered on demonstrating units under real-world conditions. However, research is needed for improved fuel reformers to efficiently provide necessary hydrogen fuel from hydrogen rich sources such as natural gas or gasoline. Additionally, fuel cells themselves have a high degree of reliability and availability due to their lack of moving parts, but are limited by the reliability of support systems such as pumps and fans needed for operation. Improvements in these areas would increase the attractiveness of fuel cells. Future research and development into turbine/fuel cell hybrids is also expected.

For fuel cells currently under development, the major obstacle is cost. The one current commercial offering costs over $4,000/kW which prevents it from competing with grid power or other micropower technologies on an economic basis other than for niche applications such as “green” power or premium power. If fuel cells are to have success in the market, they will most likely need to reach the current solid oxide (SOFC) target of $900/kW or lower. This will require substantial cost reduction, especially for the electrolytic material.

Heat Exchangers

In addition to improving the CHP prime mover, research and development is needed to improve options for the recovery of waste heat from CHP systems. While heat exchangers for generating steam or hot water have been employed for decades, devices to generate hot air for drying or other process applications are needed.

Improving CHP Cooling Options

While CHP systems have been available for years, recent improvements in the performance and availability of thermal-driven cooling technologies have brought attention to these technologies as a potential use of CHP waste heat.

With several of the largest U. S. chiller manufacturers offering absorption units, costs have been reduced, lead times reduced and availability improved. These improvements have boosted the domestic market for absorption chillers. The study results indicate about 5 GW of CHP with absorption, accounting for 15 percent of the base case market potential, growing to almost 6 GW in the future scenario. While this is seen as relatively modest growth, the companion study for buildings indicated substantial growth in the potential based largely on the drop in installed cost of single-effect absorption units, assuming a 15-30 % drop in larger units and up to 65 % drop in smaller units. This drop in costs is based on the smaller (under 100 tons) units realizing the cost position that larger (500+ tons) units have relative to their electric counterparts. This is anticipated by the period 2005-2010. Industrial applications would benefit from these cost reductions as well.

Another option that would help provide better balance between thermal output needed for absorption units and thermal output available is to permit sales of electricity back to the grid. Currently, no allowance for grid sales is incorporated in the analysis, and this would allow for larger CHP units to be sized, and thus provide more thermal output. Many states have already passed legislation that allows net metering by small renewables, with some of these programs applying to small (less than 100 kW) CHP units. Should these programs become more widespread and allow larger CHP units to net meter, this could in effect help the match between available thermal output and the size of absorption unit needed to serve cooling loads.

One other potential limitation of the study that affects CHP cooling options include the lack of consideration of heat recovery for engine driven chillers (EDCs). Should future efforts examine this issue in more detail, recommendations for improving EDC technology to boost CHP potential for industry could be developed.

Improving the CHP Package

One major challenge faced by CHP is the lack of integrated systems. Finding the optimal CHP components that, when integrated, can meet the wide range of facility heating, cooling, and electric loads is left up to the plant management and their supporting staff. In response to a recent DOE solicitation, seven industry teams have announced research, development and testing of “first generation” integrated CHP and absorption chiller with controls, some with desiccant units as well. This program holds promise for the buildings market for CHP, offering multiple benefits, including lower integration costs and risks. In addition, it is a positive step forward for the use of thermal cooling with CHP in the industrial sector.

Appendix A
METHODOLOGY

Analyzing the potential market for CHP in industrial facilities requires consideration of a number of data inputs that will determine the economics of an application. Gas and electric rates, facility load profiles, technology cost and performance, and financial parameters that govern current and future economic conditions all are essential inputs to an assessment of any particular CHP application.

This section describes how the market assessment for industrial CHP was performed, including key data inputs, a sample analysis, and the creation of scenarios for the sensitivity analyses.

Market Assessment

The industrial analysis of CHP was performed using the Contractor's DIStributed Power Economic Rationale SElection (DISPERSE) model. This tool is a spreadsheet-based model which estimates the achievable economic potential for CHP and other on-site generation by comparing various CHP options with traditional equipment and purchasing from the grid. The model not only determines whether CHP is more cost effective than other options, but also which technology combination, size, and operating mode appears to be the most economic. Figure A-1 illustrates how the DISPERSE model organizes the key data inputs and generates the desired outputs.

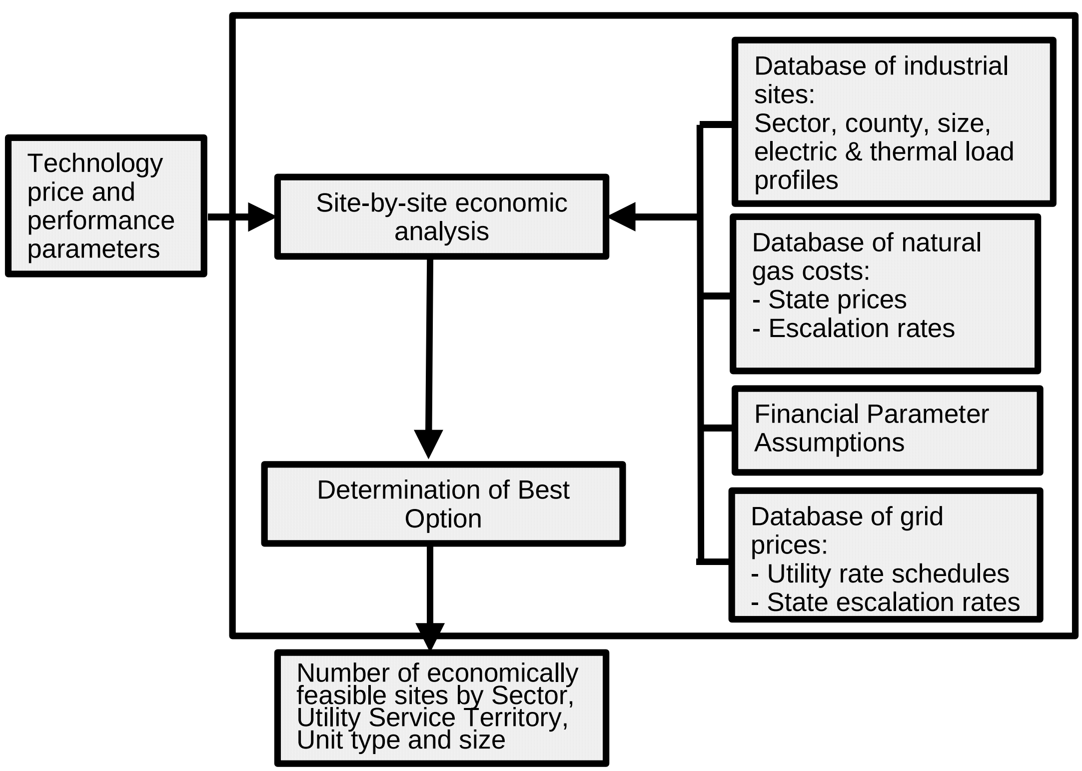


Figure A-1. DISPERSE Model

The DISPERSE model has been developed over the past five years, based on the Contractor's experience in conducting feasibility studies for CHP applications over the past two decades. The DISPERSE model has been applied on a variety of projects for utilities, equipment manufacturers, and research organizations.

Key Inputs and Assumptions for DISPERSE Methodology

The DISPERSE model performs a life-cycle cost economic analysis, based on the unit life as well as cost and performance data, electric utility rate schedules, and fuel prices. The model determines whether any CHP option can beat the case in which no power is generated on-site and all power is purchased from the local utility. The best technology option is selected based on shortest payback.

This process is repeated tens of thousands of times, once for each group of sites within a combination of a utility service area (or region)/CHP unit size range/industrial sector in the database of sites, and the results are then aggregated to obtain market potential.

Future cost and performance assumptions were made to create inputs for the sensitivity analysis described later in this section.

The following key inputs are used by the model:

1. **Technology price and performance parameters**. The model requires data on the mix of technologies that are being made available to the sites analyzed. This data includes each technology's installed cost, fuel type, heat rate, electrical efficiency, useable thermal output, operating and maintenance costs, and other key parameters. Data for CHP and cooling technologies was derived from manufacturer-provided data, and is validated by comparison with published data in journals, technical papers, and other sources. Table A-1 details the modeled price and performance characteristics for the various CHP technologies for the base case (year 1999/2000) and the future cases (2005 and beyond). Table A-2 provides the modeled price and performance data for the cooling options, including absorption and engine-driven chiller units. In this table, base case and future scenarios are shown.

Table A-1. Technology Price and Performance Inputs for CHP Units

Size	Unit Type	Base Case Current Technologies (1999/2000)					Future Technologies (2005+)				
		Package Cost ($/kW)	Operating & Maintenance ($/kWh)	Efficiency @ Rated Output	Thermal Output (BTU/kWh)	Total Installed Cost ($/kW)	Package Cost ($/kW)	Operating & Maintenance ($/kWh)	Efficiency @ Rated Output	Thermal Output (BTU/kWh)	Total Installed Cost ($/kW)
45-75kW	Engine	550	0.0150	31.0%	5.4	1033	465	0.0100	42.0%	3.4	815
	Microturbine	900	0.0100	27.1%	6.7	1383	625	0.0100	40.0%	3.8	965
75-150kW	Engine	522	0.0012	31.7%	5.2	953	425	0.0090	42.0%	3.4	730
	Microturbine	800	0.0100	27.1%	6.7	1231	575	0.0100	40.0%	3.8	860
150-300kW	Engine	506	0.0120	33.5%	4.7	880	375	0.0085	43.0%	3.4	640
	Microturbine	700	0.0090	27.1%	6.7	1074	475	0.0090	40.0%	3.8	720
	Fuel Cell	4500	0.0150	39.6%	3.8	5003	1275	0.0150	50.0%	1.7	1555
300-600kW	Engine	488	0.0100	35.0%	4.6	800	375	0.0080	43.0%	3.3	605
	Microturbine	703	0.0090	27.1%	6.7	1015	460	0.0090	40.0%	3.9	675
	Fuel Cell	4500	0.0150	39.6%	3.8	4812	1275	0.0150	50.0%	1.4	1520
.6-1MW	Engine	481	0.008	36.5%	4.5	730	370	0.008	44.0%	3.1	570
	Turbine	508	0.006	25.0%	8.2	757	480	0.006	40.0%	3.9	670
1-2.5MW	Engine	473	0.0075	38.0%	4.2	704	370	0.0075	45.0%	3.0	550
	Turbine	473	0.0055	28.0%	7.2	704	360	0.0055	40.0%	3.9	525
2.5-5MW	Engine	467	0.0075	39.0%	4.0	622	350	0.0075	45.0%	3.0	465
	Turbine	437	0.0045	29.0%	6.8	592	330	0.0045	40.0%	3.9	420
5-10MW	Engine	450	0.007	42.0%	3.1	575	335	0.007	45.0%	3.0	450
	Turbine	425	0.004	31.0%	6.2	550	325	0.004	42.0%	3.7	400
10-20MW	Engine	450	0.007	42.0%	3.1	563	335	0.007	45.0%	3.0	435
	Turbine	375	0.004	33.0%	5.6	488	325	0.004	42.0%	3.7	395

Note: Data derived from manufacturer-provided data from 1999-2000, and has been validated by comparison with published data in journals, technical papers, and other sources including Gas Turbine World 2000-2001 Handbook. Future cost data has been developed from DOE-sponsored meetings including the Microturbine Technology Summit (December 1998) and the Advanced Stationary Reciprocating Natural Gas Engine Workshop (January 1999), as well as discussions with manufacturers.

Table A-2. Technology Price and Performance Inputs for Cooling Options

Tons	Unit Type	Base Case Current Technologies (1999/2000)				Future Technologies (2005+)			
		Installed Cost ($/Ton)	Electric Use (kW/ Ton)	Fuel Input (Mbtu/ Ton)	Annual Maint-enance Cost ($/Ton)	Installed Cost ($/Ton)	Electric Use (kW/ Ton)	Fuel Input (MBtu/ Ton)	Annual Maint-enance Cost ($/Ton)
10-50	Reciprocating: Water Cooled	675	1.0	0	50	641	0.95	0	48
	Reciprocating: Air Cooled	625	1.4	0	60	594	1.3	0	57
	Absorption: Single Effect	1100	0.0	17	70	445	0.03	16	67
	Engine Driven	950	0.02	11	80	891	0.02	10	76
50-100	Reciprocating: Water Cooled	650	1.0	0	35	618	0.95	0	33
	Reciprocating: Air Cooled	600	1.3	0	50	570	1.2	0	48
	Centrifugal	675	0.8	0	40	641	0.71	0	38
	Absorption: Single Effect	800	0.03	17	40	428	0.03	16	38
	Engine Driven	900	0.0	10	65	855	0.02	10	62
100-200	Reciprocating: Water Cooled	540	0.75	0	30	513	0.7	0	29
	Reciprocating: Air Cooled	575	1.2	0	40	546	1.14	0	38
	Centrifugal	600	0.7	0	30	570	0.67	0	29
	Screw	725	0.7	0	30	689	0.67	0	29
	Absorption: Single-Effect	600	0.03	17	30	410	0.0	16	29
	Engine Driven	840	0.0	10	55	798	0.02	10	52
200-500	Reciprocating: Air Cooled	525	1.1	0	30	499	1.0	0	29
	Centrifugal	550	0.7	0	25	523	0.62	0	24
	Screw	600	0.7	0	25	570	0.7	0	24
	Absorption: Single-Effect	500	0.0	17	25	374	0.02	16	24
	Engine Driven	750	0.01	9	47	713	0.01	9	45
500-1000	Centrifugal	400	0.6	0	15	380	0.57	0	14
	Screw	525	0.65	0	15	499	0.6	0	14
	Absorption: Single-Effect	325	0.0	17	15	309	0.01	16	14
	Engine Driven	625	0.01	8	35	594	0.01	7	33
1000-2000	Centrifugal	350	0.6	0	15	333	0.57	0	14
	Absorption: Single-Effect	300	0.01	17	14	285	0.0	16	13
	Engine Driven	525	0.0	8	27	499	0.01	7	26

Note: Data derived from manufacturer-provided data from 1999-2000, and has been validated by comparison with published data in journals, technical papers, and other sources including R. S. Means Mechanical Cost Data. Future cost data has been developed by reducing installed cost and efficiency by 5 percent (consistent with the cost reduction shown for CHP units).

2. **Database of industrial sites and facility characteristics.** Location, size, and SIC code of industrial sites are taken from U. S. Department of Commerce County Business Pattern data. Electricity consumption and peak demand per employee data is based on census division data from DOE's 1998 Manufacturing Energy Consumption Survey (MECS). Load profiles are taken from Contractor-collected data, and include data on electric and thermal usage on an hour-by-hour basis. Process cooling loads are derived from MECS data and incorporated into the load profiles.

3. **Database of fuel prices**. Natural gas costs are based on state prices from EIA's Natural Gas Monthly for year 1999. Sensitivities were included (as documented later in this section) that capture the effect of recent price increases in natural gas. Industrial prices are used to approximate the rate that would be paid by a facility utilizing natural gas cooling or combined heat and power (CHP), which is typically lower than small commercial rates. Natural gas escalation rates are based on regional forecasts of industrial gas prices from EIA's Supplement to the Annual Energy Outlook (2001).

4. **Database of grid prices**. Rate schedules (year 2000) of the 68 largest electric utilities (in terms of GWh sales to industrial customers) representing over two-thirds of deliveries to the industrial sector were utilized (see Table A-3). Customers in counties not served by the largest utilities were assigned a regional rate schedule derived from schedules of major utilities within that region. Escalation rates are based on regional forecasts from EIA's Supplement to the Annual Energy Outlook (2001), using industrial electric prices. Furthermore, backup charges are included at $50/kW annually (or $4.20/kW/month).

5. **Financial parameter assumptions**. Table A-4 contains a list of financial assumptions. A project life of 10 years is assumed, reflecting the anticipated life of smaller CHP projects and conservative financial planning from customers. Units are expected to be funded by the customer from their operations. Insurance is included as an annual operating cost, as well as costs of standby power, and taxes are applied after all costs and savings are totaled. No sales of electricity back to the grid are assumed.

Table A-4. Financial Parameter Assumptions

Project Length (years)	10
Federal Income Tax (%)	35
State Income Tax (%)	5
Property Tax and Insurance (%)	2
Discount Rate (%)	8

Table A-3. Utilities Included In DISPERSE for Industial Facilities

1. Alabama Power Co
2. Appalachian Power Co
3. Baltimore Gas & Electric Co
4. Carolina Power & Light Co
5. Central Power & Light Co
6. Cincinnati Gas & Elec Co
7. Cleveland Electric Illum Co
8. Commonwealth Edison Co
9. Connecticut Light & Pwr Co
10. Consumers Energy Co
11. Dayton Power & Light Co
12. Detroit Edison Co
13. Duke Energy Corp
14. Entergy Arkansas Inc
15. Entergy Gulf States Inc
16. Entergy Louisiana Inc
17. Florida Power and Light
18. Florida Power Corp
19. Georgia Power Co
20. Green River Electric Corp
21. Houston Lighting & Pwr Co
22. Idaho Power Co
23. IES Utilities Inc
24. Illinois Power Co
25. Indiana Michigan Power Co
26. Indianapolis Pwr & Light Co
27. Kentucky Utilities Co
28. Massachusetts Electric Co
29. Memphis City of
30. Metropolitan Edison Co
31. MidAmerican Energy Co
32. Minnesota Power Inc
33. Mississippi Pwr Company
34. Monongahela Power Co
35. Nevada Power Co
36. Niagara Mohawk Pwr Corp
37. Northern Indiana Pub Serv
38. Northern States Power Co
39. Ohio Edison Co
40. Ohio Power Co
41. Oklahoma Gas & Elec Co
42. Pacific Gas & Electric Co
43. PacifiCorp
44. PECO Energy Co
45. Pennsylvania Electric Co
46. Potomac Edison Co
47. PP&L Inc
48. PSI Energy Inc
49. Pub Service Co of Colorado
50. Pub Svc Co of Oklahoma
51. Pub Svc Co of New Mexico
52. Pub Svc Electric & Gas Co
53. Puget Sound Energy Inc
54. Sacramento Municipal Util
55. Salt River Project
56. San Antonio Pub Svc Bd
57. South Carolina Elec&Gas
58. S. Carolina Pub Svc Auth
59. Southern California Edison
60. Southwestern Electric Pwr
61. Texas Utilities Electric Co
62. Toledo Edison Co
63. Tucson Electric Power Co
64. Union Electric Co
65. Virginia Electric & Pwr Co
66. West Penn Power Co
67. Wisconsin Electric Pwr Co
68. Wisconsin Pwr & Light Co

Initial Grouping of Sites

The model run begins with a database of potential customer sites that are organized by utility service area, facility type (SIC code), and size. Sites are organized as follows:

- Utility/Region and Industrial Facility Type – Number of facilities are taken from U. S. Department of Commerce County Business Patterns (CBP), which indicates where all industrial facilities are located and number of employees. From this data, the sites are assigned to a utility based on their county (see Table A-3 for a list of utilities that are included) using a Contractor database. Sites outside of these utility areas are assigned to one of the nine census regions based on their state.

- Facility Size – Based on the number of employees, an industrial facility peak demand and annual kWh consumption is estimated using data on kW and kWh per employee (from MECS data for each SIC code and region). Table A-5 summarizes the input data on number of sites, annual electricity consumption, and sites with peak demands over 56 kW, which was used as a cutoff to eliminate sites too small for consideration. This assumption was based on the minimum size unit (28 kW) considered, and applying that unit in a baseload configuration which would require a 56 kW peak demand to yield a 50 percent load factor.

Table A-5. Summary of Industrial Sites Analyzed

SIC/Industry	All Industry		Sites Analyzed			
	Annual MWhs Consumed	Number of Sites	Annual MWhs Consumed	Share of All Industry MWh	Number of Sites	Share of All Industry Sites
20 Food	72,922,480	21,132	71,781,296	98.4%	12,509	59%
21 Tobacco	2,116,506	140	2,113,080	99.8%	99	71%
22 Textiles	41,006,540	6,176	40,696,588	99.2%	4,110	67%
23 Apparel	10,061,381	23,779	8,704,864	86.5%	6,934	29%
24 Lumber	28,851,582	37,133	26,913,270	93.3%	8,925	24%
25 Furniture	8,624,855	12,271	8,046,328	93.3%	4,736	39%
26 Paper	66,931,396	6,535	66,594,600	99.5%	4,715	72%
27 Printing	24,182,360	62,453	19,401,482	80.2%	11,160	18%
28 Chemicals	153,730,720	12,364	153,059,552	99.6%	7,308	59%
29 Petroleum	44,179,784	2,143	44,005,792	99.6%	1,355	63%
30 Rubber/Plastics	57,901,232	16,794	56,972,436	98.4%	11,691	70%
31 Leather	1,162,735	1,854	1,073,904	92.4%	588	32%
32 Stone/Clay/Glass	40,012,440	16,557	38,631,760	96.5%	6,544	40%
33 Primary Metals	147,990,672	6,614	147,710,928	99.8%	5,131	78%
34 Fabricated Metals	59,505,096	38,582	57,278,620	96.3%	21,632	56%
35 Machinery	62,882,532	56,620	58,717,032	93.4%	20,898	37%
36 Electrical Equip.	61,826,456	17,329	60,920,272	98.5%	9,701	56%
37 Transportation Equip.	65,833,432	12,659	65,239,504	99.1%	6,192	49%
38 Instruments	21,952,144	11,929	21,316,654	97.1%	5,743	48%
39 Misc. Mfg.	6,787,301	18,373	5,796,095	85.4%	3,556	19%
Admin/Auxiliary	21,325,939	11,623	N/A	N/A	N/A	N/A
TOTALs	999,787,583	393,060	954,974,056	95.5%	153,527	39%

Source: U. S. Department of Commerce, 1996 County Business Patterns, and U. S. Department of Energy, 1998 Manufacturing Energy Consumption Survey.

This data was used to create a set of combinations of utilities, customer sectors and DG unit sizes for economic analysis.

Determining the Most Economic DG Option

DISPERSE estimates the most economic technology and unit size that independently meets the electric demand for a particular facility type in a particular utility. To do so, the model calculates cash flows from gas and electric purchases over a 10-year period for each situation. The simple payback and Net Present Value (NPV) is then calculated from either generating with CHP or purchasing electricity to meet consumption needs for each combination of utility, SIC code, generating unit size, and CHP/cooling technology option. Generation or purchase of electricity is considered at each hour and is matched to an 8,760-hour demand profile over the year. In each case, one technology offers the most economic net energy costs, including capital, O&M, electricity, and fuel costs for a particular utility, sector and size combination.

The model analyzes up to 18 different equipment, sizing, and operating scenario options for each site in addition to calculating the cost of operating a boiler to generate needed steam/hot water and of purchasing electricity from the grid. This large number of scenarios is indicative of the fact that different options are best for different sites depending on many factors, most importantly site load profile and utility rate schedule. The list of potential options analyzed (options considered for any given site will be dependent on the site's peak demand and need for cooling) is shown in Table A-6. Cooling options are included in the analysis at the incremental cost over conventional electric cooling options, assuming that the units would be installed when replacement of the existing chiller is required.

Table A-6. Technology Options

Options	
• Engine driven chiller sized at peak cooling load	• Advanced turbine system w/absorber
• Engine driven chiller sized for baseload cooling	• Advanced turbine system w/heat recovery
• Engine w/absorber	• Advanced turbine system w/o heat recovery
• Engine w/ heat recovery	• Fuel cell w/absorber
• Engine w/o heat recovery	• Fuel cell w/ heat recovery
• Turbine w/absorber	• Fuel cell w/o heat recovery
• Turbine w/ heat recovery	• Combined cycle w/absorber
• Turbine w/o heat recovery	• Combined cycle w/ heat recovery
	• Combined cycle w/o heat recovery

The sizing of units by the model is derived by calculating the size of the unit necessary to meet 50 percent of the site's annual electricity consumption, and usually results in a unit that is between 35-50 percent of the site peak demand. This sizing practice has been adopted from industrial sector strategies which indicate that many of the installed units are roughly sized at 40-50 percent of peak demand. The one exception to this sizing rule is for units with absorption chillers. For these units, a two-pronged sizing rule is applied. First, the absorption unit is sized at peak cooling load, and the thermal requirements of the absorber are used to determine the size of the power generation unit (using the thermal output values shown in Table A-1). If the resulting size of the power generation unit would result in serving over 50 percent of the annual consumption, the power generation unit is downsized to that level and the absorption unit is re-sized to fit the thermal output that is available.

Table A-7 provides results from a sample analysis for a food processor (SIC 20) located in the TU Electric service area with a 196 kW peak site demand. This analysis shows that the most attractive option is an engine driven chiller, with a 2.6 year payback. This payback is helped by the relatively low gas rates, relatively high electric rates, and the low incremental cost of an engine driven chiller. This option has the lowest electricity bill savings of any of the alternatives, but also has by far the lowest capital cost. Other options that have reasonable but less attractive paybacks (5-7 years) are a 34 kW reciprocating engine with absorber, 28 kW microturbine with absorber, and 76 kW engine CHP installation. None of the straight power generation options offer positive paybacks, nor do the fuel cell options.

Table A-7. Sample Analysis for 196 kW Food Processor

	EDC @ Peak Cooling	Engine w/ Absorber	Turbine w/ Absorber	Fuel Cell w/ Absorber	Engine CHP	Turbine CHP	Fuel Cell CHP	Straight Engine	Straight Turbine	Straight Fuel Cell
Base-Line Characteristics										
Electricity										
Energy (kWh)	1,308,235	1,308,235	1,308,235	1,308,235	1,308,235	1,308,235	1,308,235	1,308,235	1,308,235	1,308,235
Demand (kW)	196	196	196	196	196	196	196	196	196	196
Boiler Fuel (MMBtu)	5,954	5,954	5,954	5,954	5,954	5,954	5,954	5,954	5,954	5,954
Cooling Contribution (kW peak)	12	12	12	12	12	12	12	12	12	12
Installed Tons	8	8	8	8	8	8	8	8	8	8
Necessary Chiller Capital ($ / ton)	625	625	625	625						
Necessary Chiller Maint. ($ / ton / yr)	60	60	60	60						
DG System Characteristics										
Gen-Set or CHP:										
Power Generated (kWh)		298,503	243,598	393,299	662,664	662,664	662,664	662,664	662,664	662,664
Peak Output (kW)		34	28	45	76	76	76	76	76	76
Load Factor		99%	99%	100%	100%	100%	100%	100%	100%	100%
Rated Eff. @ Full Load		33%	27%	40%	33%	27%	40%	33%	27%	40%
Fuel Consumption (MMBtu)		3,152	3,100	3,369	6,957	8,374	5,653	6,957	8,374	5,653
Gen-Set Capital Cost ($ / kW)		785	1,075	4,690	990	1,280	5,000	785	1,075	4,690
Cooling Equipment:										
Equivalent Installed kW	14	N/A	N/A	N/A						
Max Site Reduction (kW)	12	12	12	12						
Fuel Consumption (MMBtu)	586	N/A	N/A	N/A						
Equivalent 'Produced' kWh's	78,494	78,494	78,494	78,494						
Installed Tons	10	10	10	10						
Capital Cost ($ / ton)	950	1100	1100	1100						
Maint. ($ / ton / yr)	80	70	70	70						
New Site Parameters										
Electricity										
Energy (kWh)	1,230,862	931,237	986,143	836,442	645,571	645,571	645,571	645,571	645,571	645,571
Demand (kW)	184	150	156	139	120	120	120	120	120	120
Cooling Demand (kW)	0	0	0	0	12	12	12	12	12	12
Boiler Fuel (MMBtu)	5,954	5,407	5,264	5,407	2,795	2,199	3,436	5,954	5,954	5,954
Energy Expense (excluding DG unit fuel)										
Original Electric Bill	81,073	81,073	81,073	81,073	81,073	81,073	81,073	81,073	81,073	81,073
New Electric Bill	76,357	59,721	62,770	54,457	44,274	44,274	44,274	44,274	44,274	44,274
Net Electric Bill Benefit (Expense)	4,716	21,352	18,303	26,616	36,799	36,799	36,799	36,799	36,799	36,799
Original Boiler Fuel Bill	16,666	16,666	16,666	16,666	16,666	16,666	16,666	16,666	16,666	16,666
New Boiler Fuel Bill	16,666	15,133	14,734	15,133	7,824	6,154	9,618	16,666	16,666	16,666
Net Boiler Fuel Benefit (Expense)	-	1,533	1,932	1,533	8,842	10,512	7,048	-	-	-
DG System Expense:										
Effective DG Capital Costs	4,325	32,737	35,937	217,305	74,890	96,828	378,233	59,383	81,320	354,782
Fuel	1,640	8,821	8,676	9,430	19,473	23,440	15,822	19,473	23,440	15,822
Variable O&M	-	3,602	2,453	5,925	7,952	6,627	9,940	7,952	6,627	9,940
Fixed O&M	302	202	202	202	-	-	-	-	-	-
Backup Charges	706	1,713	1,400	2,254	3,782	3,782	3,782	3,782	3,782	3,782
Miscellaneous Customer Benefits										
Avoided Interruptions	423	1,028	840	1,353	2,269	2,269	2,269	2,269	2,269	2,269
Customer Cash Flows										
Capital Cost	4,325	32,737	35,937	217,305	74,890	96,828	378,233	59,383	81,320	354,782
Net Electricity Bill	4,716	21,352	18,303	26,616	36,799	36,799	36,799	36,799	36,799	36,799
Net Boiler Fuel Bill	-	1,533	1,932	1,533	8,842	10,512	7,048	-	-	-
DG Unit Fuel	1,640	8,821	8,676	9,430	19,473	23,440	15,822	19,473	23,440	15,822
DG Unit Maintenance	302	3,804	2,654	6,126	7,952	6,627	9,940	7,952	6,627	9,940
Back Up Charges	706	1,713	1,400	2,254	3,782	3,782	3,782	3,782	3,782	3,782
Avoided Interruptions	423	1,028	840	1,353	2,269	2,269	2,269	2,269	2,269	2,269
Property Taxes and Insurance	87	655	719	4,346	1,498	1,937	7,565	1,188	1,626	7,096
Depreciation	433	3,274	3,594	21,731	7,489	9,683	37,823	5,938	8,132	35,478
Tax Effect	690	1,976	1,411	(5,035)	2,701	1,439	(10,085)	257	(1,588)	(11,567)
Net Cash Flow (1st Year)	1,714	6,944	6,214	12,380	12,505	12,356	19,093	6,416	5,182	13,996
NPV ($)	5,787	7,061	26	(136,294)	(963)	(24,647)	(249,058)	(34,857)	(67,341)	(266,999)
Payback	2.6	5.1	6.4	N/A	6.5	9.0	N/A	N/A	N/A	N/A
NG rate ($ / MMBtu)	2.8									

Sensitivity Analyses

A number of scenarios were constructed to evaluate how sensitive the base case is to varying inputs. Some of these scenarios were intended to focus on how improving the cost and/or the efficiency of CHP impacts the market size. Others were developed to illustrate the effects of changing energy prices on the industrial CHP market.

As shown in Table A-8, a total of 6 scenarios were analyzed. The first three involved current (1999) energy prices, with either current (1999/2000) unit cost and performance or anticipated future changes in unit cost and performance (2005+), as documented in Tables A-1 and A-2.

Table A-8. Scenarios Depicted by Sensitivity Analyses

Scenario	CHP Unit Cost and Performance	Cooling Option Cost and Performance	Energy Prices
1. Base Case	Current	Current	Current
2. Future	Future	Future	Current
3. Future Package	Future	Future w/Package Cost Reduction	Current
4. Moderate FAC	Current	Current	Moderate Prices with Fuel Adjustment Clause
5. High FAC	Current	Current	High Prices with Fuel Adjustment Clause
6. Peak FAC	Current	Current	Peak Prices with Fuel Adjustment Clause

The second three sensitivities involved changing energy prices. As shown in Figure A-2, natural gas prices increased dramatically in late 2000 and through 2001, changes not reflected in the base case gas prices. As a result of this increase in prices, industry experts forecasted a range of expectations, with some calling for high prices to last a couple of years and others predicting long term impacts. As a result, two alternative gas price scenarios were developed: 1) moderate prices (Moderate FAC), which calls for wholesale natural gas prices to hover around $5/MMBTU for 2001-2002, and 2) high prices (High FAC), which calls for the $5/MMBTU wholesale prices to persist for the ten years up to 2010. Figure A-3 provides an example showing the Pacific Census Region, illustrating these scenarios for industrial gas prices (as stated earlier, industrial prices are used to approximate the rate that would be paid by a facility utilizing natural gas cooling or combined heat and power, and are typically lower than small commercial rates but higher than prices utilities pay). These scenarios were not adopted as an expectation of future prices, but simply to examine the impact on the industrial CHP market should either scenario emerge.

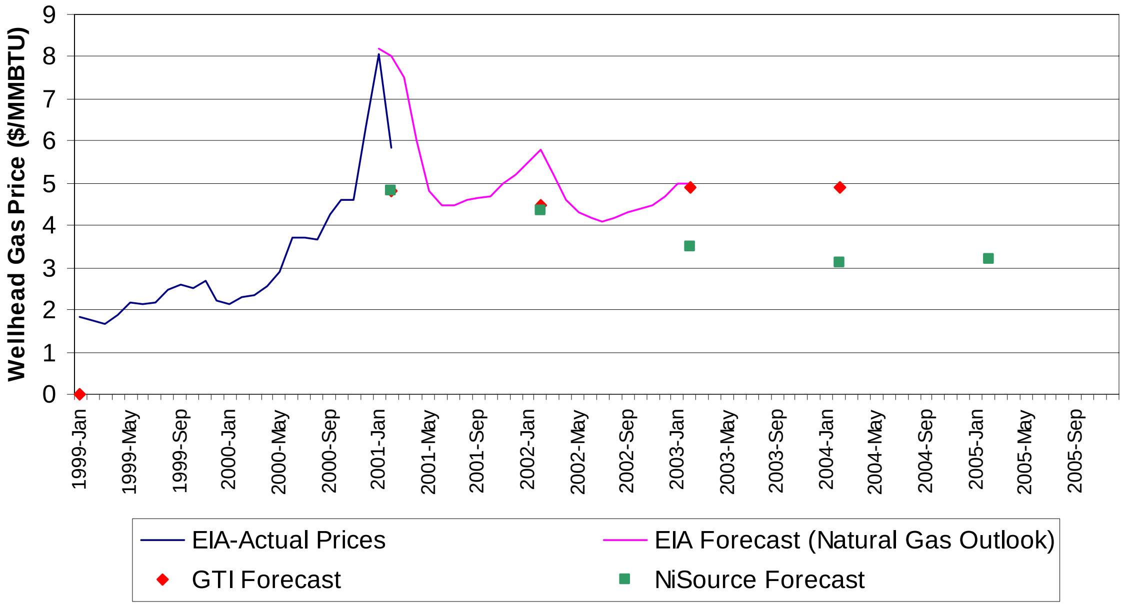


Figure A-2. Natural Gas Price Increase (Through March 2001) and Industry Forecasts

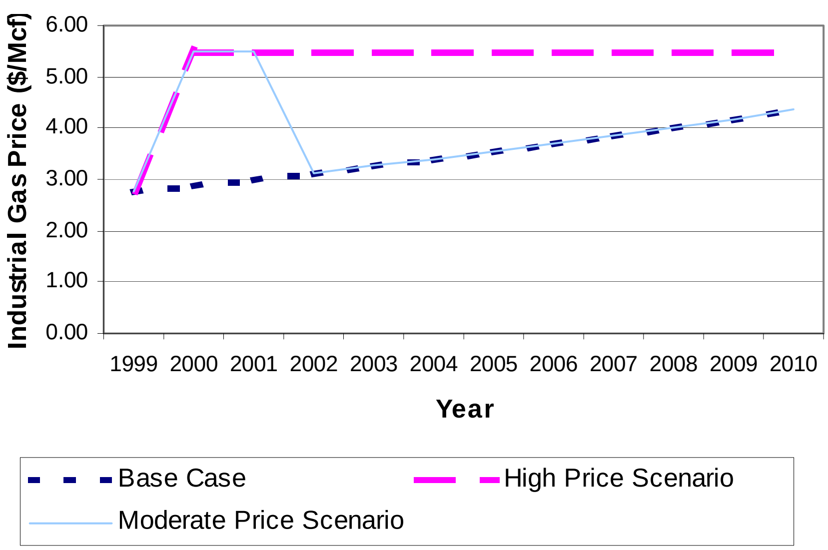


Figure A-3. Natural Gas Price Sensitivities Relative to Base Case (Industrial Gas Prices for Pacific Region only)

Since it is generally accepted that there is convergence in gas and electric prices, translating the effect of high natural gas prices on industrial electric rates was important in analyzing these scenarios. To accomplish this, a methodology was developed to estimate the increase in fuel costs by state, and allocate those costs to the amount of electricity generation to derive an updated electricity price. This method is similar to how utilities calculate their fuel adjustment clause.

Based on this analysis, states such as California, Nevada, Texas, Louisiana, Oklahoma, New York and Rhode Island were estimated to have state-level fuel adjustment clauses (FAC) over 0.5 cents per kWh. These states, as shown in Table A-9, are among those with the highest percentage of gas-fired generation, and also have experienced some of the highest increases in utility gas prices. These fuel adjustment clauses were applied along with the gas prices sensitivities by using the FAC for the 2000-2010 timeframe for the high price case, and only for 2000-2001 for the moderate price case.

Lastly, a final price scenario (Peak FAC) was added to see how the market for CHP would be affected if the increase in gas prices was reflected solely as a demand-based charge. While this value would likely ultimately be embodied only in the limited number of peak pricing hours (e.g. the 200 highest-priced hours), it was difficult to do so for this analysis. The increase in gas prices paid by generators was divided by the peak demand, and thus a $/kW charge was calculated. This value ranged from over $50/kW annually (over $4/kW per month) for parts of Texas down to less than $1/kW annually for a number of areas including Kentucky and other parts of the nation with low shares of natural gas-fired generation.

Table A-9. Estimation of Fuel Adjustment Clauses

State	Utility and Non Utility Generation (Million kWh in 2000)			Utility Gas Price ($/Mcf)			Estimated Natural Gas Cost ($000)		Cents per kWh added fuel cost
	Total Gas Gen	Total Gen	% Gas	1999	2000	% Chg	1999	2000	
Alabama	5,216	122,254	4%	2.79	5.16	85	41,306	53,025	0.1
Alaska	3,940	5,782	68%	1.59	1.76	11	39,950	45,013	0.1
Arizona	8,855	88,790	10%	2.68	4.57	71	54,650	95,857	0.2
Arkansas	3,516	43,424	8%	2.6	4.09	57	47,003	36,557	0.1
California	106,196	206,652	51%	2.76	4.85	76	857,870	1,062,564	1.1
Colorado	6,740	43,243	16%	2.69	3.71	38	41,691	61,448	0.1
Connecticut	4,977	36,150	14%	2.7	4.5	67	33,572	44,193	0.2
Delaware	986	5,880	17%	2.88	4.83	68	21,963	9,213	0.3
DC	0	89	0%	3.09	4.61		0	0	0.0
Florida	43,194	189,647	23%	3.12	4.48	44	399,723	372,298	0.3
Georgia	3,304	123,698	3%	2.57	4.3	67	38,244	38,737	0.1
Hawaii	376	8,600	2%	5.62	8.41		387	387	0.0
Idaho	186	11,200	1.7%	4.11	5.26		3,058	1,036	0.0
Illinois	5,168	179,216	3%	2.4	4.66	94	68,449	57,045	0.1
Indiana	5,469	120,077	5%	2.97	4.9	65	121,182	138,165	0.2
Iowa	466	42,008	1.1%	3.07	4.46	45	6,839	6,244	0.0
Kansas	2,824	44,777	6%	2.36	4.06	72	36,256	33,479	0.1
Kentucky	307	83,200	0%	3.21	5.42	69	5,680	4,063	0.0
Louisiana	44,516	89,733	50%	2.59	4.25	64	486,704	501,383	0.9
Maine	1,363	11,700	12%	2.87	3.27		595	15,094	0.1
Maryland	3,316	49,751	7%	3.09	4.61	49	35,108	45,121	0.1
Mass.	11,127	39,353	28%	2.7	4.52	67	95,125	95,298	0.4
Michigan	12,795	104,319	12%	1.52	2.95	94	142,827	137,672	0.2
Minnesota	881	48,028	2%	2.58	4.32	67	14,500	13,242	0.0
Mississippi	8,441	37,267	23%	2.47	3.89	57	116,769	110,090	0.4
Missouri	2,936	76,784	4%	2.64	4.38	66	19,832	30,330	0.1
Montana	29	29,000	0%	4.11	5.26	28	1,085	437	0.0
Nebraska	466	29,076	2%	2.74	4.66	70	4,723	5,590	0.0
Nevada	12,828	35,689	36%	2.49	4.36	75	87,720	120,577	0.6
New Hamp.	106	15,064	1%	2.87	3.27	14	768	977	0.0
New Jersey	17,514	58,043	30%	3.06	4.38	43	149,754	167,246	0.4
New Mexico	4,651	33,440	14%	2.3	3.75	63	43,756	51,427	0.2
New York	39,140	136,031	29%	2.83	4.53	60	437,901	374,644	0.5
N. Carolina	958	127,214	1%	2.85	4.52	59	13,324	10,593	0.0
N. Dakota	52	28,350	0%	2.58	4.32		268	268	0.0
Ohio	891	146,404	1%	3	4.73	58	15,738	12,811	0.0
Oklahoma	17,497	55,179	31%	2.76	4.3	56	181,012	179,731	0.5
Oregon	8,782	51,499	17%	1.93	2.74	42	51,982	75,112	0.1
Pennsylvania	3,202	225,074	1%	3.02	3.92	30	34,230	31,935	0.0
Rhode Island	5,746	5,850	98%	2.7	4.5	67	33,429	47,082	1.4
S. Carolina	903	96,187	1%	3.63	5.6	54	11,265	8,728	0.0
S. Dakota	224	8,975	3%	2.58	4.32		2,526	3,599	0.1
Tennessee	648	130,618	1%	3.21	5.42		10,488	8,240	0.0
Texas	195,532	374,142	52%	2.5	4.01	60	1,752,303	2,060,922	0.8
Utah	1,228	35,878	3%	2.64	3.78	43	7,779	14,303	0.0
Vermont	91	6,200	2%	3.23	4.87	51	249	1,021	0.0
Virginia	4,065	76,686	5%	3.16	4.67	48	41,548	37,208	0.1
Washington	6,933	108,712	6%	2.76	4.85		36,185	71,996	0.1
West Virginia	269	5,168	5%	2.98	4.8	61	2,602	2,742	0.1
Wisconsin	1,986	60,249	3%	2.93	4.28	46	25,449	23,768	0.1
Wyoming	551	41,472	1%	4.07	3.92	-4	4,583	6,543	0.0

Source: Utility natural gas prices were taken from the EIA Natural Gas Monthly (March 2001), along with quantity of gas purchased from EIA Cost and Quality of Fuels (1999), and utility generation from EIA Form 759 and 900.

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