FINAL REPORT

Integrated Energy Systems (IES) for Buildings: A Market Assessment

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EXECUTIVE SUMMARY

Combined heat and power (CHP) has evolved in recent years, incorporating potentially high value Thermally Activated Technologies (TAT) like cooling and humidity control. The CHP Technology Roadmaps (Buildings and Industry) have focused research and development on a comprehensive integration approach: component integration, equipment integration, packaged and modular system development, system integration with the grid, and system integration with building and process loads. This marked change in technology research and development has led to the creation of a new acronym to better reflect the nature of development in this important area of energy efficiency: Integrated Energy Systems (IES).

Integrated Energy Systems (IES) combine on-site power or distributed generation technologies with thermally activated technologies to provide cooling, heating, humidity control, energy storage and/or other process functions using thermal energy normally wasted in the production of electricity/power. IES produce electricity and byproduct thermal energy onsite, with the potential of converting 80 percent or more of the fuel into useable energy. Integrated Energy Systems have the potential to offer the nation the benefits of unprecedented energy efficiency gains, consumer choice and energy security.

This market assessment confirms that the current IES research and development projects targeting the commercial building sector have the potential to:

1. dramatically reduce fossil fuel use and air pollutant emissions
2. improve the electric grid's power quality, efficiency, reliability and return on investment
3. enhance energy security

This study supports and guides IES projects by assessing technologies and markets where IES is positioned for growth. Furthermore, this effort will identify areas where technology needs improvement and where substantial barriers exist, and the potential market effects of overcoming these obstacles. As a result, this study sought to quantify the buildings market for IES, identify key market drivers and barriers, and explore potential areas for technology research and development that could improve the prospects for IES.

The analysis revealed that the potential building sector market for IES is almost 17 GW in 2010, growing to over 35 GW by 2020, and includes IES systems with absorption chillers, engine-driven chillers (EDCs), and CHP-only systems. *This market potential is based on achievable economics*, where IES provides a minimum payback of 10 years compared with conventional HVAC systems and purchasing electricity from the grid. Many of the IES options analyzed provide paybacks much lower than 10 years, with a significant portion under 4 years.

As shown in Figure ES-1, the market potential includes both system turnover in existing buildings, as well as IES in new buildings. Included in this potential are increased absorption chillers (8.9 million tons), added thermal storage (3.2 million tons), and more engine driven chillers (2.4 million tons). Together, if implemented this market potential would represent almost 18 million metric tons of reduced carbon dioxide emissions (based on carbon equivalent) annually by the year 2020, and would contribute significantly to meeting goals originally established by the Kyoto Protocol. This reduction in carbon emissions is based on displacing grid emissions from average U. S. utility plants.

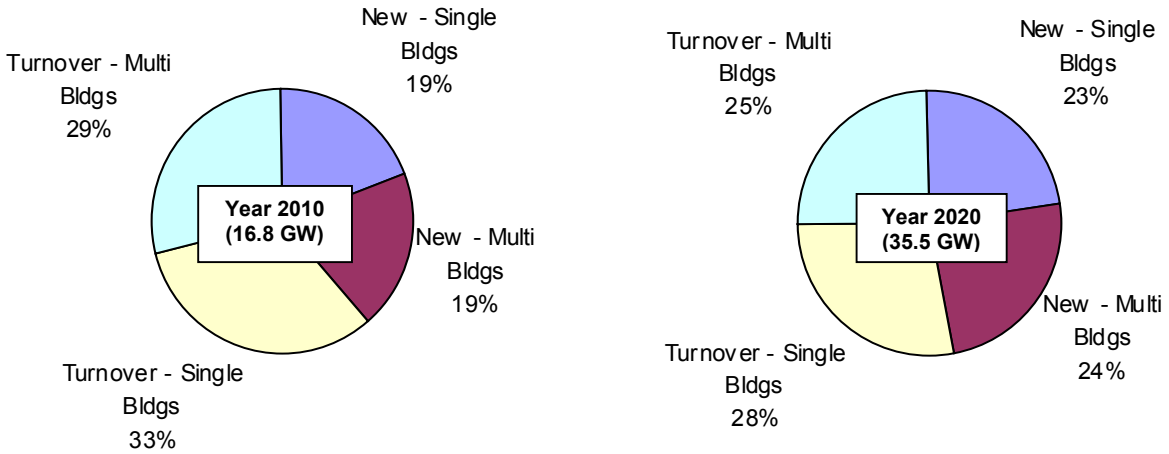


Figure ES-1. IES Market Potential for New and Existing Single and Multi-Building Facilities

One important, but recognized, shortcoming of this market assessment is the exclusion of Integrated Energy Systems (IES) employing desiccant dehumidification technologies. Prior to the 1997 ASHRAE Handbook of Fundamentals[1], design professionals lacked data describing extreme moisture load conditions. Cooling and dehumidification systems (typically air conditioning systems) are usually designed based on extreme temperature conditions and fall far short of capacity when moisture really reaches its peak – usually at moderately warm temperatures. Thus, although it is felt that excluding IES with desiccant dehumidification in this initial market assessment is a reasonable representation of current conditions in the U.S., a follow-up assessment effort is planned. That supplementary assessment will include consideration of new ASHRAE design moisture data and ventilation standard requirements and will likely show penetration by IES/desiccant combination systems and, as a result, will increase the total market potential.

To date, most IES is concentrated in education and health care buildings. The education sector includes universities, which have long used CHP as a means of controlling utility costs. While some barriers still exist in this sector, such as the price of backup power and the regulated market for surplus power, other barriers such as first cost have not been factors in IES market penetration. Similarly, hospitals have a smaller but still significant installed base of CHP.

For other building sectors, the economics of IES holds promise, but barriers prevent widespread adoption. As shown in Figure ES-2, the potential for IES is highest in office buildings, with over 10 GW of total

[1] American Society of Heating, Refrigerating, and Air Conditioning Engineers, ASHRAE Handbook 1997 Fundamentals, Atlanta GA, 1997.

IES, including significant opportunities for CHP with absorption units and engine-driven chillers (45 percent of the office potential). Of that 4.5 GW, CHP with absorbers represent over 3.6 GW and EDCs 1.1, giving offices almost half of the total EDC potential.

Hospitals and colleges, while already established in CHP use, each offer over 7 GW of potential for IES, respectively. Schools, retail, and hotels are smaller segments, but with their significant heating and cooling loads offer additional IES potential. Military bases also offer potential for IES, but generally for CHP-only systems. Military bases do not generally have base-wide cooling distribution systems.

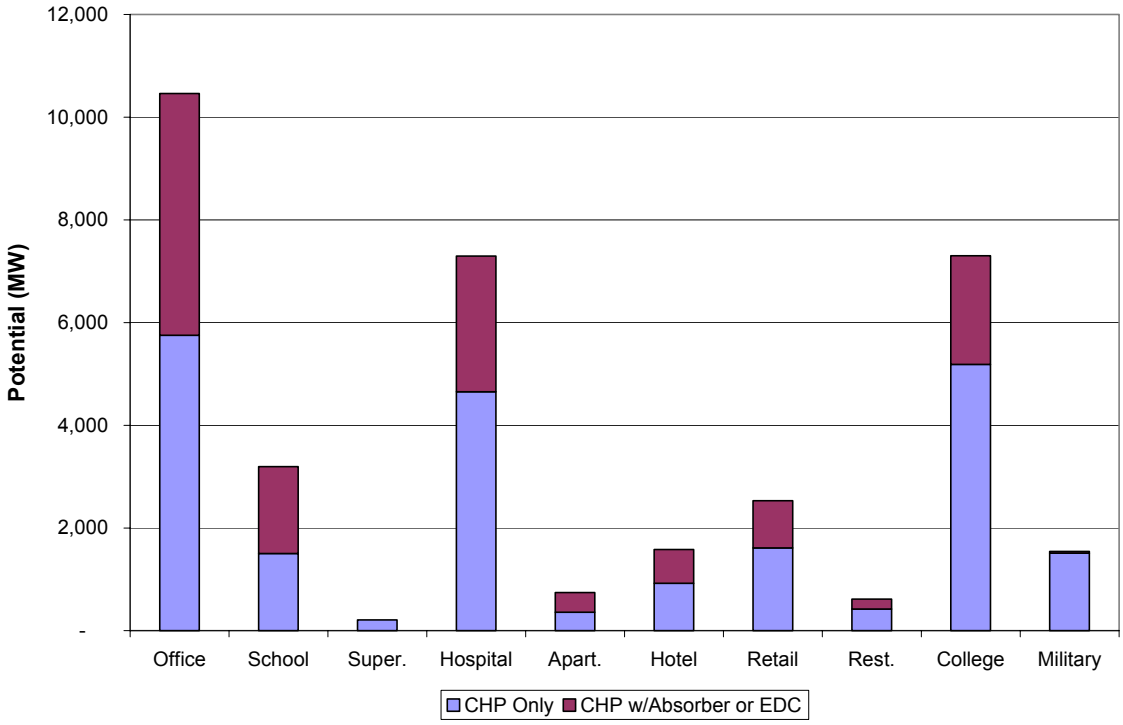


Figure ES-2. IES Potential by Building Type

The study also examined a number of scenarios to evaluate how sensitive the base case is to varying inputs. In doing so, there was a focus on how improving the cost and/or the efficiency of IES impacts the market size. In addition, three sensitivities were added to illustrate the effects of changing energy prices on the IES market for buildings (see Table ES-1).

Overall market potential results of the sensitivity analysis (see Figure ES-3) indicate that improvement in the installed cost and efficiency increases the market size dramatically. Both future scenarios increase the potential market from 35 to almost 70 GW, nearly doubling the market size.

Table ES-1. Scenarios Depicted by Sensitivity Analyses

Scenario	IES 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	Current	Current	Moderate Prices with Fuel Adjustment Clause
5. High	Current	Current	High Prices with Fuel Adjustment Clause
6. Peak	Current	Current	Peak Prices with Fuel Adjustment Clause

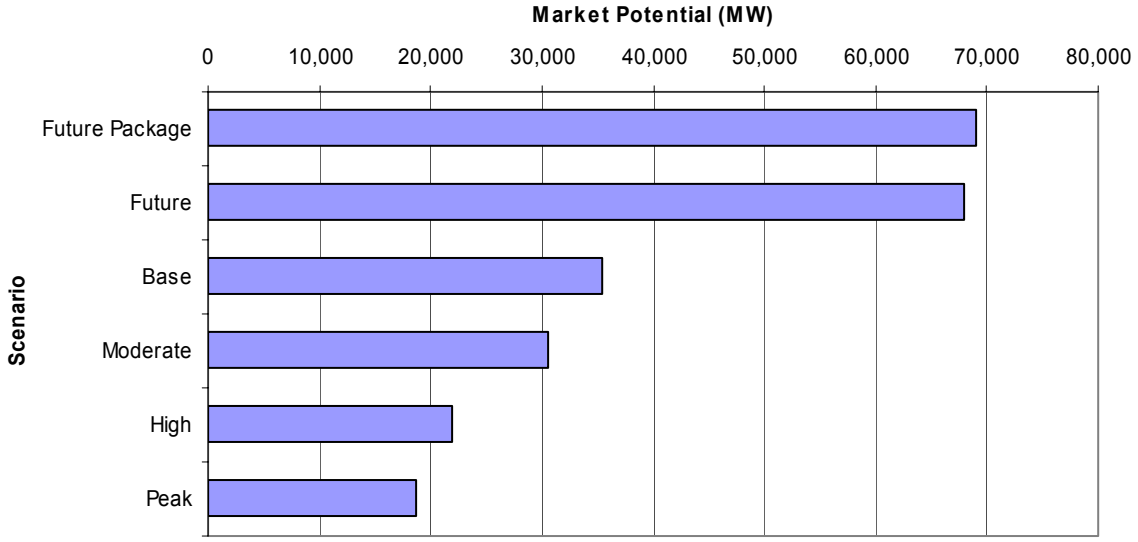


Figure ES-3. Future Scenarios Offer Highest Market Potential

The energy price sensitivities tell another story. On the surface, it appears that higher energy prices lead to less potential for IES. Figure ES-4 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.

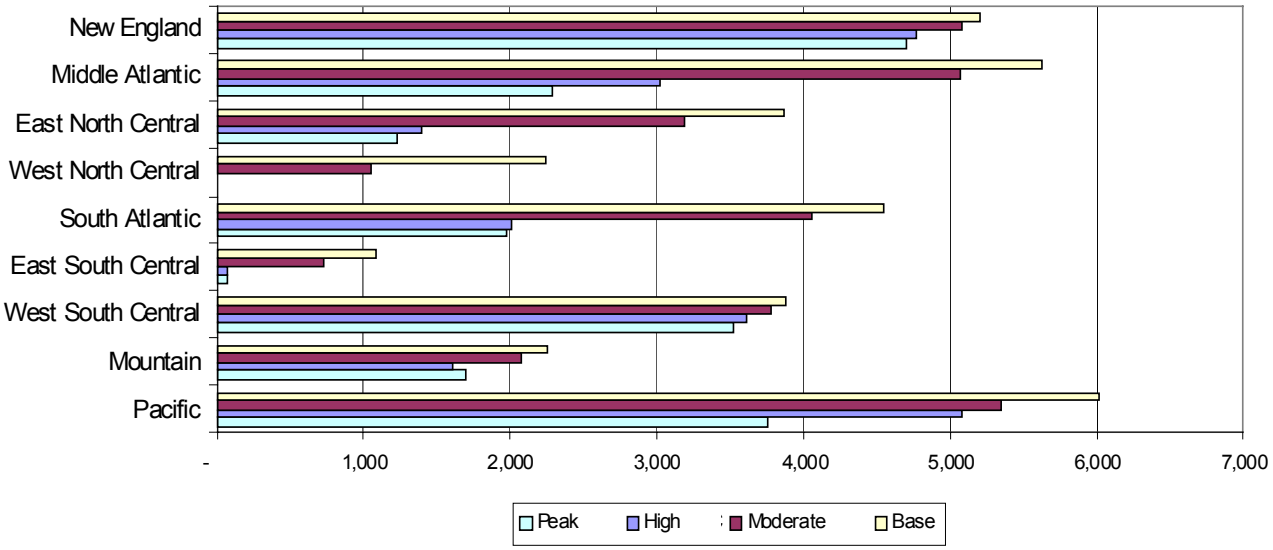


Figure ES-4. Regional Effects of Price Sensitivities on IES

The major factor driving this impact is the combination of high electricity prices and use of thermal energy, as the economics of IES in general improve with high prices if the thermal utilization is high. The study supports this, with the IES heating only configurations offering improved market potential with high electricity and natural gas prices in regions of the country where the share of gas-fired generation is high, such as the Pacific, Mountain, West South Central, and New England. In these regions, the prices of electricity and gas tend to move together, with electric prices increasing significantly as gas prices rise.

Other portions of the U.S., such as the East North Central, West North Central, East South Central, and South and Middle Atlantic have more coal and nuclear generation, and thus are less affected by rise in gas prices. Current IES performance tends to be penalized in these portions of the country when gas prices rise. However, this trend may change since many new intermediate duty and peaking plants are natural gas turbines which will change the future dynamics of this marketplace.

Despite improving economics, increasing emphasis on overall energy efficiency, and steps taken toward restructuring of the electric utility industry, a number of hurdles stand in the way of realizing the benefits inherent in implementing IES on a wide scale. Applications in the U.S. buildings market are currently limited 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

Among these categories, some barriers of particular importance include:

1. The lack of standardized systems (engineering and field integration of individually designed pieces of equipment requires high quality engineering and high cost labor) which are in short supply and are expensive.
2. The need to better match coincident electric and thermal loads with IES system capabilities.
3. Supporting market infrastructure.
4. Antiquated and prohibitive policies and regulations.
5. Lack of application and integration knowledge.

These barriers can often make an IES project appear unattractive, and can present such an uncertain or difficult option to potential end users that more traditional HVAC and purchased power approaches are favored. To overcome these barriers and maximize the many benefits of IES in the buildings sector, further R&D and IES application successes are needed to allow these technologies to compete with more conventional options.

While the R&D needs vary by technology, the overall goal should be to support industry in developing lower cost integrated IES packages and or modular IES that improve source energy efficiency and reduce operating costs. These packages or modular systems should cover a wide range of sizes and options to fit with the varied needs of the buildings sector. Furthermore, integration of these IES into building systems and with the grid requires that a new series of application know-how and empirical data be developed and transferred to building owners, architects, consulting engineers, contractors, policy makers, regulators and code officials.

Section 1
INTRODUCTION

Integrated Energy Systems (IES) combine on-site power or distributed generation technologies with thermally activated technologies to provide cooling, heating, humidity control, energy storage and/or other process functions using thermal energy normally wasted in the production of electricity/power. IES produce electricity and byproduct thermal energy onsite, with the potential of converting 80 percent or more of the fuel into useable energy. IES have the potential to offer the nation the benefits of unprecedented energy efficiency gains, consumer choice and energy security. It may also dramatically reduce industrial and commercial building sector carbon and air pollutant emissions and increase source energy efficiency.

Applications of distributed energy and CHP in *Commercial and Institutional Buildings* have, however, been historically limited due to insufficient use of byproduct thermal energy, particularly during summer months when heating is at a minimum. In recent years, custom-engineered systems have evolved incorporating potentially high-value services from Thermally Activated Technologies (TAT) like cooling and humidity control. Such TAT equipment can be integrated into a CHP system to utilize the byproduct heat output effectively to provide absorption cooling or desiccant humidity control for the building during these summer months. IES can therefore expand the potential thermal energy services and thereby extend the conventional CHP market into building sector applications that could not be economically served by CHP alone. Now more than ever, these combined cooling, heating and humidity control systems (IES) can potentially decrease carbon and air pollutant emissions, while improving source energy efficiency in the buildings sector.

Even with these improvements over conventional CHP systems, IES face significant technological and economic hurdles. Of crucial importance to the success of IES is the ability to treat the heating, ventilation, air conditioning, water heating, lighting, and power systems loads as parts of an integrated system, serving the majority of these loads either directly or indirectly from the CHP output. The CHP Technology Roadmaps (Buildings and Industry) have focused research and development on a comprehensive integration approach: component integration, equipment integration, packaged and modular system development, system integration with the grid, and system integration with building and process loads. This marked change in technology research and development has led to the creation of a new acronym to better reflect the nature of development in this important area of energy efficiency: Integrated Energy Systems (IES). Throughout this report, the terms “CHP” and “IES” will sometimes be used interchangeably, with CHP generally reserved for the electricity and heat generating technology subsystem portion of an IES.

The focus of this study is to examine the potential for IES in buildings when the system perspective is taken, and the IES is employed as a dynamic system, not just as conventional CHP. This effort is designed to determine market potential by analyzing IES performance on an

hour-by-hour basis, examining the full range of building types, their loads and timing, and assessing how these loads can be technically and economically met by IES.

Status of IES

While IES use in U.S. buildings is in its infancy, CHP systems have been in limited use in the buildings sector for decades. A number of data sources disagree on how many buildings currently use CHP, with Utility Data Institute figures citing about 2,600 MW and DOE's Energy Information Administration (EIA) posting totals of about 1,900 MW. Independent energy organizations, such as the District Energy Library (www.energy.rochester.edu), hosted by the University of Rochester, cites CHP installations in educational institutions that surpass those quoted by these sources. In the report District Energy Systems Integrated with Combined Heat and Power, prepared by Mark Spurr of the International District Energy Association for the U.S. Environmental Protection Agency (EPA), Spurr examines these data sources and concludes that the total CHP serving buildings through District Energy Systems (DES) can be estimated at 3,500 MW. Comparing these figures with the total (industrial and buildings) CHP of about 46,000 MW in 1998, CHP in the buildings sector is only about 5-10 percent of the installed base.

While the overall size of CHP in the buildings sector is somewhat uncertain, most agree that this market is led by educational facilities, with the health care sector also important. Some of the factors that drive the favorable economics of CHP in these building types are:

- Occupancy levels are generally high, with students or patients occupying the facilities around the clock, creating high load factors that help amortize the investment in CHP systems,
- The balance between thermal and electric loads in these building types is relatively high (can a balance be high?) , compared with other building types,
- Multiple buildings under common ownership, so that electricity, heating, and cooling loads can be aggregated and served by a central system that is larger and more cost effective than several smaller systems,
- Close proximity of buildings, so that connecting buildings with hot water/steam/chilled water distribution piping is not cost prohibitive,
- Buildings are occupied by the "owners" and not leased to tenants, so a higher degree of control and comfort is generally desirable.

Figure 1-1 illustrates the building sectors represented in the EIA data, with other sectors including airports and other transportation services, miscellaneous services, and entertainment/lodging also represented. These facilities generally share some, but not all, of the factors that are common in educational and health care institutions.

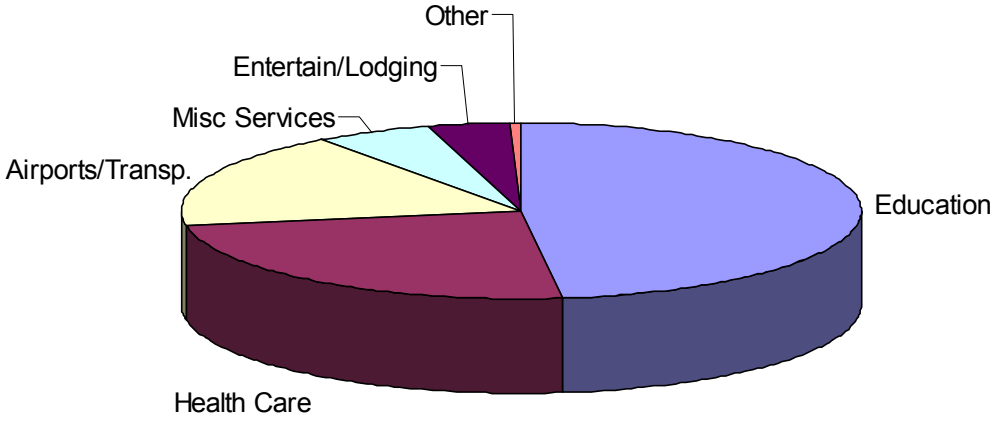


Figure 1-1. CHP Capacity in the Buildings Sector, by Building Type (EIA 1998, total of 1,870 MW)

DOE Objectives

DOE's focus on IES for buildings is part of a broader initiative aimed at increasing the use of IES. Assistant Secretary Dan Reicher announced a national goal of doubling the CHP capacity by 2010 at the CHP Summit in December of 1998. Since then, the Office of Energy Efficiency and Renewable Energy (EERE) has established the CHP Challenge to achieve this goal. With published levels of CHP at about 46 GW in 1998, this goal means adding an additional 46 GW by 2010. While it is generally agreed that the majority of this growth in CHP capacity would originate in the industrial sector, the building sector was seen as a source of new CHP to supplement industrial levels. As a result, the IES Initiative was founded to identify opportunities and barriers to applying a wide range of CHP and TAT technologies in buildings. The IES Initiative will also seek out appropriate actions among the growing number of industry, institutional, and governmental entities focused on the broader IES marketplace.

This study supports and guides IES projects by assessing technologies and markets where IES is positioned for growth. Furthermore, this effort will identify areas where technology needs improvement and where substantial barriers exist, and the potential market effects of overcoming these obstacles. As a result, this study will:

- Summarize the current state-of-the-art in cooling technologies that can be employed in the buildings sector within an IES, including absorption, desiccant, and engine-driven units,
- Quantify the buildings market for IES, and model the performance of these units so that the full range of economic benefits can be incorporated,
- Identify key market drivers and barriers, and

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

While this effort focuses on the buildings sector, there are companion studies being completed that examine the potential for CHP in industry, and its ability to provide significant contributions to the CHP Challenge goal.

Section 2

IES FOR BUILDINGS
STATE OF THE ART

It is widely agreed that IES is a technology option that is underutilized in the building sector. While some of this is due to the insufficient economic returns related to seasonal heating and cooling loads, there are institutional reasons why IES is not more widely used in buildings. Many building owners make their decisions on the basis of first cost, and IES options tend to cost more than conventional alternatives. Furthermore, the building design community tends to be risk adverse, favoring the "tried and true" alternatives and not recommending options that they have not specified before. As a result, the vast majority of buildings do not include IES.

A number of trends, however, are creating a IES-favorable environment for buildings. Electricity industry restructuring, while promising lower rates for larger users, has many building owners concerned over rising prices and decreasing grid reliability. Furthermore, new standards of indoor air quality call for increased ventilating rates and has helped renew interest in desiccant dehumidification, which changes the economics of humidity control in buildings and establishes another application for CHP waste heat. Finally, independent third parties such as ESCOs and utilities are investing in district CHP systems, offering buildings new opportunities for savings without large investments.

Other factors that are creating a more IES favorable environmental are global warming issues that have surfaced from the Kyoto protocol. The increased energy efficiency that can result from widespread use of CHP and IES is being counted on in many policy scenarios that have resulted from Kyoto compliance strategies. While industrial CHP is seen as critical to these scenarios, IES for buildings is also being counted upon.

This section provides an overview of the state-of-the-art of IES components for buildings. It defines IES as it is applied to buildings and reviews the state-of-the-art for the many components that comprise an IES, including the prime mover and the various cooling options that can be coupled with CHP to form an IES for buildings.

Defining IES

IES are defined as the co-production of power along with heat for heating, domestic water heating, and thermal-driven cooling and humidity control. This includes using a variety of CHP technologies along with absorption chillers or desiccant dehumidification systems. In addition, engine driven chillers coupled with heat recovery are also included. Figure 2-1 provides an illustration of these options depicted serving the whole range of stand-alone building energy requirements, and Figure 2-2 illustrates these options for multiple buildings.

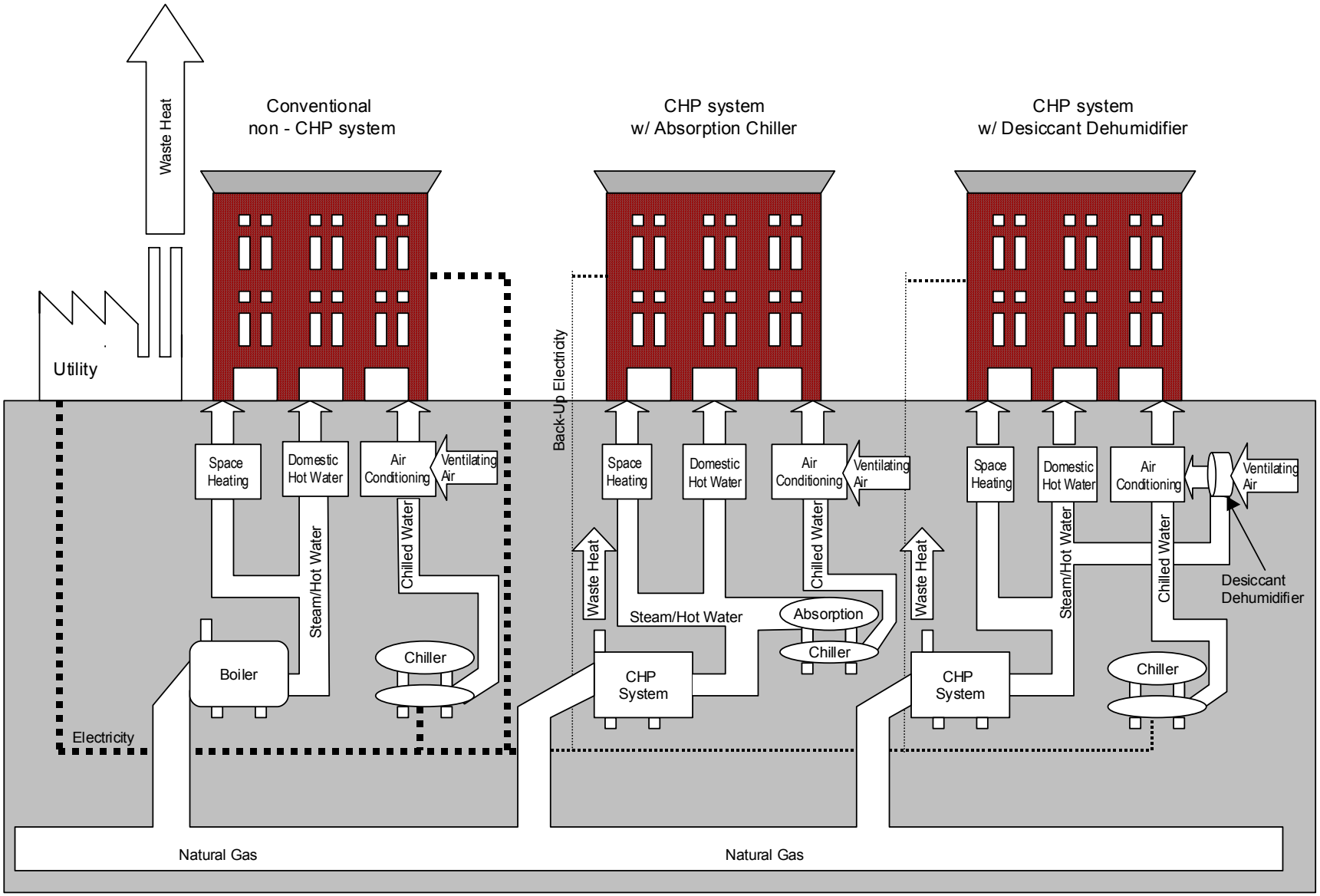


Figure 2-1. IES Options for Single Buildings

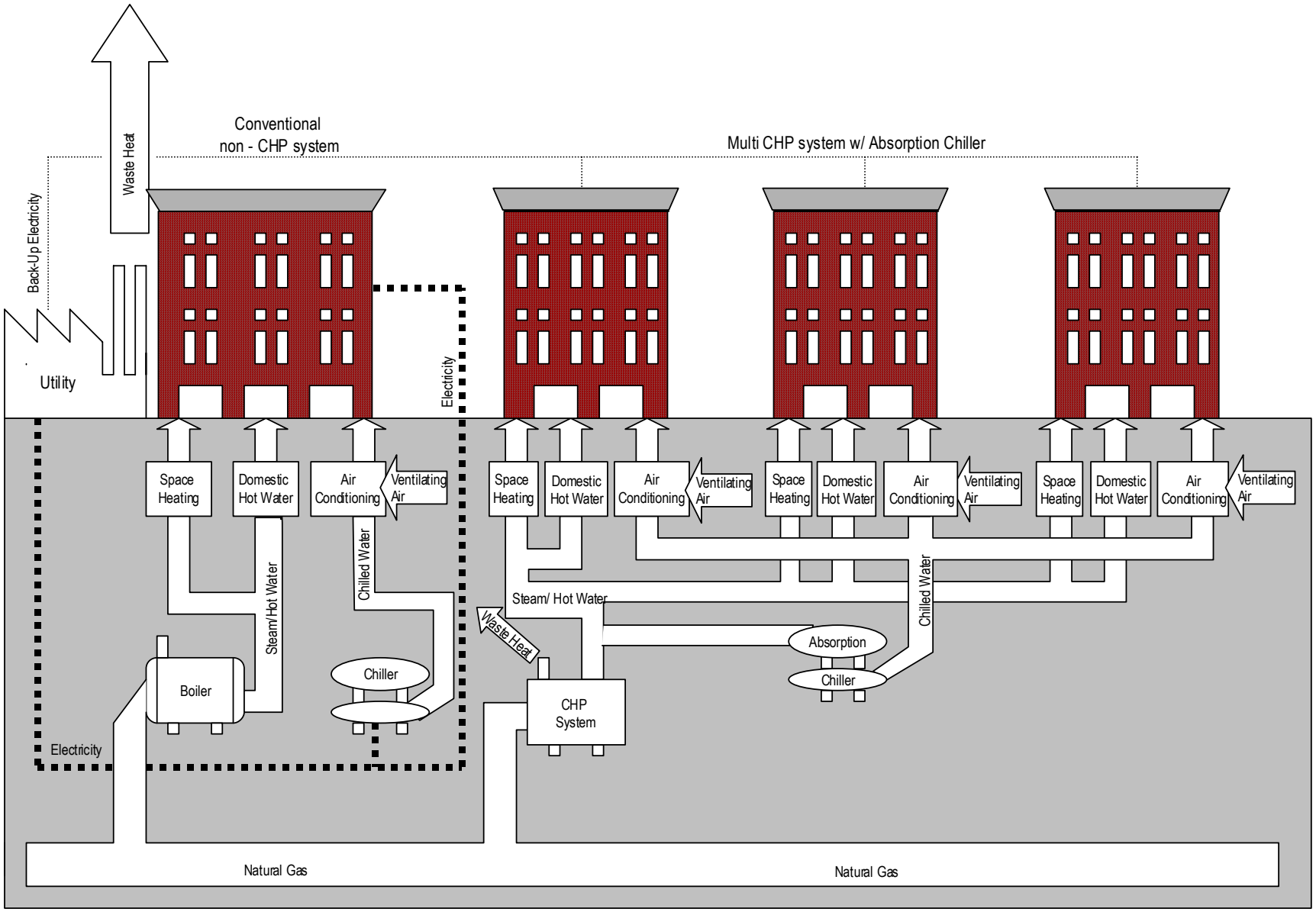


Figure 2-2. IES Options for Multiple Buildings

CHP Systems

A number of advances in CHP systems 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 advanced technologies will challenge the ways that facilities currently 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.

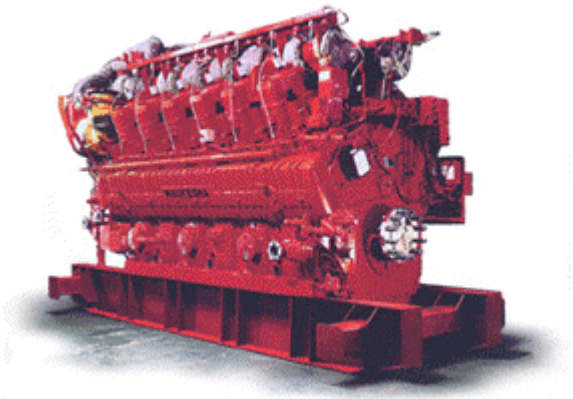


Figure 2-3. Waukesha ATGL (1.2 – 2.5 MW) Series Natural Gas Engine

Both diesel (compression ignition) and natural gas (spark ignition) engines are widespread. However, due to emission regulations, it is becoming increasingly hard to site diesel generators, except those used as emergency backup units generally operated less than 200 hours annually due. New engine CHP applications are focused primarily on natural gas fired spark ignited (SI) units in the 60 kW to 4 MW size range, although some use dual fuel engines (described below). Most installed natural gas units are stoichiometric, though newer units, especially in larger sizes, focus on lean-burn technology which allows for increased efficiency and lower emissions from the combustion chamber.

The primary pollutant of concern for natural gas fired SI engines is NO_x. Temperature is the primary driver of NO_x formation but nitrogen in the fuel, pressure in the cylinder, and residence times at elevated temperature/pressure also have a role in the amount of NO_x that will ultimately be produced.

Manufacturers have developed dual fuel engines up to 8 MW that are beginning to achieve some market penetration. While most of these are larger, smaller units are being tested. Dual fuel engines take advantage of natural gas emissions, economics, and convenience while keeping the efficiency, lower maintenance, and reliability benefits of compression ignition technology. Dual fuel engines 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. Additionally, significant reductions in emissions can be obtained by incorporating a pre-ignition chamber that lowers the amount of diesel pilot fuel necessary for ignition.

Noise can be an issue with reciprocating engines, particularly in urban areas. Sound enclosures may be required to reduce ambient noise to acceptable levels.

Turbines

Combustion turbines have been used for power generation for decades, ranging 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 promising low emissions, relatively low maintenance, and other benefits are emerging and will provide competition for smaller reciprocating engines.

Figure 2-4. Rolls-Royce Allison 501-K Turbine Power Package

Traditionally, turbine applications have been limited by lower electrical efficiencies to CHP uses at industrial and institutional settings and peaking units for electric utilities. However recent advancements in turbine technology brought about by the Department of Energy Advanced Turbine Systems (ATS) program promise to increase efficiencies of commercial units through advanced materials, cycles, and recuperation.

Combustion turbines feature relatively low installed cost, low emissions, and infrequent maintenance. With these advantages, combustion turbines are typically used for CHP 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 for emergency, standby, or peak shaving applications, mostly due to their higher cost, lower electrical efficiency and longer startup time when compared with reciprocating engines designed for these purposes. Some users, however, have shown a preference to 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. Multiple stages are typical and differentiate these turbines, along with axial blading, from smaller microturbines, which have radial blades and are single staged. An intercooler that cools combustion air between compressor stages may be employed but is usually reserved for larger turbines that can economically incorporate the cost of this improvement in efficiency.

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. In addition, these methods increase power production but often reduce the system efficiency. While these means have been proven effective in limiting NO_x emissions, the availability of water supply, cost of water treatment, and space for storage tanks are constraints for some applications. In many states, these measures are deemed adequate to meet NO_x regulations.

Dry Low NO_x (DLN) combustors are being increasingly used to reduce emissions further and eliminate the need for the water supply and storage associated with water or steam injection. DLN creates a lean, homogeneous mixture of air and fuel prior to the combustor, minimizing hot spots which create higher NO_x concentrations, and overall reducing the combustion temperature leading to lower NO_x levels, down to about 25 ppm in CHP sized units and to under 10 ppm in larger, central station units. Conceptually, this method is similar to lean-burn technology for reciprocating engines. This method has become the standard for NO_x control in combustion turbines.

Fuel Cells

Fuel cells are an emerging class of small-scale power generation technology in the mostly in the under 1 MW size range although larger units are under development. The first fuel cell was developed in the 1800s but 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 (formerly International Fuel Cells/ONSI), currently manufactures a 200 kW fuel cell that is being used in commercial and industrial applications. A number of other companies are currently field testing demonstration units, and commercial deliveries are expected in 2002-2005.

From FuelCells.org

Figure 2-5. Fuel Cell Energy's 2 MW Molten Carbonate Fuel Cell power plant demonstration in Santa Clara, California

The main differentiation among fuel cell types is in the electrolytic material. Each different electrolyte has benefits and detriments 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 (>200 kW) size range. Both operate at higher temperatures and require long "startup" time, so are well suited to baseload power generation or CHP. Unlike the development of other power generating technologies, fuel cell development is focused more on getting units to work and demonstrating effectiveness than on refining current models.

Although fuel cells were first designed as purely electric generators, they have 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 which have a good power to volume ratio. PEMs also have some potential for providing residential power. However, for the most part, fuel cells primarily used for power generation such as Phosphoric Acid, Solid Oxide, and Molten Carbonate, are not suited for transportation use.

Fuel cells require hydrogen for operation. Since it is often 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, although the sulfur content of biogases can require extensive additional pretreatment to avoid contaminating fuel cell catalysts.

Unit Price and Performance

While price and performance data on reciprocating engines and turbines is fairly well established, data for fuel cells is based on a limited number of demonstration projects. As a result, comparisons of price and performance should be interpreted with some uncertainty. The price and performance of engines, turbines, and fuel cells is summarized in Table 2-1. This information was collected from a number of manufacturers and their distributors. The market analysis presented in the next section is based on representative units taken from this data.

Table 2-1. Cost and Performance of CHP Systems

Technology	Engine	Turbine and Microturbine	Fuel Cell
Size	30kW – 8MW	30kW - 20+MW	100-3000kW
Installed Cost ($/kW)[1]	300-1500	350-1500	2000-5000
Elec. Efficiency (LHV)	28-42%	14-40%	40-57%
Overall Efficiency[2]	~80-85%	~85-90%	~80-85%
Variable O&M ($/kWh)	.0075 - .02	.004-.01	.002-.05
Footprint (sqft/kW)	.22-.31	.15-.35	.9
Emissions (lb / kWh unless otherwise noted)	Diesel: NO_x: .022-.025 CO: .001-.002 NG: NO_x: .0015-.037 CO: .004-.006	NO_x: 3-50ppm CO: 3-50ppm	NO_x: <.00005 CO: <.00002
Fuels	Diesel, NG, gasoline, digester gas, biomass and landfill gas; larger units can use dual fuel (NG/Diesel) or heavy fuels	NG, diesel, kerosene, naphtha, methanol, ethanol, alcohol, flare gas, digester gas, biomass and landfill gas	NG, propane, digester gas, biomass and landfill gas (potentially)

[1]Cost varies significantly based on siting and interconnection requirements, as well as unit size and configuration.
[2]Assuming CHP.

Some of the critical price and performance issues are as follows:

Installed Cost. Installed cost is a critical consideration for many sites, and drives the economics of on-site generation. Having the incumbent technologies, *reciprocating engine and turbine* manufacturers must continue to reduce prices, especially if fuel cell manufacturers meet their cost targets. *Turbines*, on average, tend to be more expensive than competing natural gas reciprocating engine units under 1 MW, and more expensive than diesel recips, but tend to be less expensive in the larger (5+ MW) size range.

Supplemental equipment needed for fuel processing, gas compression, recuperation, and control systems is a significant portion of overall costs, so improvements here may go a long way toward meeting overall price targets. *Fuel cells* have, by far, the highest capital costs of technologies. Substantial cost reductions, primary in the stacks, are needed to allow fuel cells to compete with other generating technologies and the grid.

A key contributor to installed costs is the interconnection package, although these costs are most significant for smaller (<500 kW) applications. Connecting a genset to the grid can be very costly. The cost for engineering and equipment necessary to meet utility interconnection requirements can vary substantially from utility to utility, and may increase total capital costs significantly. The Institute of Electrical and Electronic Engineers (IEEE) is developing a standard for interconnecting units to the grid thatshould, when fully implemented, substantially reduce the uncertainty and costs associated with interconnection.

Efficiency**.** For *engines*, electrical efficiency is quite high compared to turbines. Improvements in design of combustion chamber, cylinder heads, and fuel injection are slated to increase Brake Mean Effective Pressure (BMEP) and improve efficiency and emissions. This may prove necessary if the cost of fuel cells becomes competitive. *Turbines* currently possess the lowest electrical efficiency of the options though advances in the ATS program promise to lessen these differences. Currently the low electrical efficiency of turbines less than 10 MW limits them to CHP and some peaking applications. Advanced recuperator designs and materials are crucial to increasing efficiency of simple cycle units. Increasing electric efficiency to 40% or greater will almost certainly require effective recuperation, advanced materials, or multi-staged designs. Combined cycle configurations where combustion turbines are paired with steam turbines are now the standard for larger baseloaded units (200+ MW), and are being developed in smaller sizes to offer efficiencies over 40 percent. However there is always a trade off between costs and efficiency, and currently costs are driving the CHP market, with simple cycle units by far the most common technology selected. *Fuel cells* promise to offer the highest efficiency of all options, but again are challenged by their lack of demonstrated performance. For each of these options, better efficiency also means lower emissions, particularly carbon emissions, which is critical for success in the U.S. market.

Emissions. *Engines* have higher emissions of CO, NO_x, and particulates than competing technologies and are thus at a disadvantage in geographic areas with stringent emission criteria, or when the customer wants to be perceived as "Green." Using catalysis to reach acceptable emissions levels is often expensive. *Turbines* have a strong advantage over engines in terms of emissions. Current expectations for NO_x emissions are already below those of engines, and future improvements call for single digit ppm emissions. Coupled with the fact that areas with strict emission limits tend to have relatively high electricity costs, low emission units will have a strong advantage in gaining market share. *Fuel cells* by nature of their lack of a combustion process have extremely low emissions of NO_x and CO. As emissions standards become increasing stringent, fuel cells will offer a

clear advantage, especially in severe non-attainment zones. Fuel cell CO_2 emissions are also generally lower than other technologies due to their higher efficiencies.

Reliability / Availability**.** *Engines* require more periodic maintenance than competing technologies and thus have more mandatory downtime. Due to the often very high cost of utility backup power, downtime can be very expensive. In addition, reliance on outside service providers or in-house staff for this maintenance can be a concern for some facilities. *Turbines* potentially have lower maintenance requirements than engines. The under 1 cent per kWh level of larger turbines allows them to be more competitive with similar-sized reciprocating engines. *Fuel cells*, themselves, have no moving parts and therefore have the potential to have very low maintenance. However, support systems such as pumps and fans necessary for the operation of the fuel cell can be costly to maintain and result in increases in both scheduled and unscheduled downtime. Also stack replacements, required at 40,000 hours (estimated) to keep efficiency high, add significantly to maintenance cost. Again, fuel cells have not been demonstrated long enough to validate these expectations.

Useful Thermal Output**.** From *engines*, usable thermal output comes from the jacket water, exhaust gases, and the oil. The ability to capture and utilize all available thermal output is dependent on effective heat exchangers and conducive site thermal load. In order for a majority of an engine's thermal output to be utilized, the output must be used for either hot water or low temperature steam. All *turbine* thermal output is in the exhaust, which gives it an advantage over engines in that heat recovery is from only one stream and at higher temperatures. Turbines thus have a greater potential to generate steam, and can be advantageous in sites with high steam requirements. However, as with engines, some of the turbine thermal output needs to be utilized in the heating of relatively low-temperature water to achieve high overall efficiencies. In addition, recuperated units have relatively low exhaust temperature and cannot produce significant amounts of steam. High temperature *fuel cells* such as molten carbonate or solid-oxide fuel cells are designed to produce heat of higher quality than that of reciprocating engines or even turbines. These fuel cells are better suited than engines or turbines to meet the thermal needs of sites with a high quality steam demand.

Future Improvements

Based on technical literature and interaction among manufacturers and other industry participants during the workshops, expectations of future cost and performance improvements were formulated. Each technology is expected to improve in the next 5 to 10 years and could result in significantly improved economics and greater market potential.

Absorption Chillers

Absorption chillers are an important option for IES building applications. They employ CHP thermal output during cooling periods when heating uses are limited to domestic hot

water loads or zonal heating, which may be small in many building types. These units involve a complex cycle of absorbing heat from the CHP system to create chilled water. The waste heat from the CHP system is used to boil a solution of refrigerant/absorbent, most systems using water and lithium bromide for the working solution. 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, which replaces the electrical compressor in a conventional electric chiller. In doing so, the electrical requirements are significantly reduced, requiring electricity only to drive the pumps that circulate the solution.

This process is employed by single-effect chillers. Double-effect units are available which add another boiling and condensing step at 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, which are 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, turbines, and fuel cells. Both direct-fired (typically natural gas) and indirect-fired (typically using steam or hot water) units are available. With the focus of this study being 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 had 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 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. The cost and performance of single-effect, indirect-fired absorption units is summarized in Table 2-3.

Table 2-2. Cost and Performance of Single-Effect, Indirect-Fired Absorption Chillers

Tons	Cost ($/ton)	Electric Use (kW/ton)	Thermal Input (Mbtu/ton)	Maintenance Cost ($/ton annual)
10-100	700-1200	.02-.04	17-19	30-80
100-500	400-700	.02-.04	17-18	20-50
500-2000	300-500	.02-.05	17-18	10-30

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 cooling 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 space heating and/or domestic hot water loads. Since most buildings have limited periods of coincidence heating, most of the thermal output is used for domestic hot water heating. Although EDCs with heat recovery show promise for applications with large hot water loads such as hotels or hospitals, for this analysis it was assumed that EDC systems would not be combined with heat recovery.

Like conventional electric chillers, EDCs are available with three different types of compressors. In the below 200 ton range, 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 BCHP systems, and emissions controls for installations located within areas of strict environmental regulations, such as ozone nonattainment areas. Table 2-3 provides the cost and performance data on engine-driven chillers.

Table 2-3. Cost and Performance of Engine Driven Chillers

Tons	Cost ($/ton)	Electric Use (kW/ton)	Thermal Input (Mbtu/ton)	Maintenance Cost ($/ton annual)
10-100	800-1050	.05-.07	9-12	45-100
100-500	650-950	.01-.05	8-11	35-75
500-2000	450-750	.003-.01	7-8	25-60

Desiccant Dehumidification Systems

Conventional electric chiller systems control humidity by cooling air to a lower temperature where the air can no longer hold as much moisture. This moisture condenses on the cooling coil, and when the cool, dry air mixes with the remaining air in the building, it effectively reduces the humidity level within the building. The reduction of temperature is referred to as the sensible load, and the removal of moisture in the air is defined as the latent load. Conventional chiller systems, however, can only control humidity when they are operating. During periods when cooling is not needed, conventional chillers can only remove humidity by overcooling the ventilating air to remove moisture, and reheating the dehumidified air to the comfort level of the building

occupants. This process of overcooling and reheat is very energy inefficient, and increases building operating costs. In the past, however, ventilation rates have been held low to conserve energy, and humidity control has been less critical and often ignored.

In the late 1980s, however, there was a push to improve Indoor Air Quality (IAQ) due to several incidences where insufficient ventilation has led to "sick building syndrome" and health problems among building occupants. ASHRAE Standard 62-89 (since updated to 62-2000) recommends 15 cfm per person as a minimum ventilation rate, increasing this baseline from its previous value of 5 cfm per person. With higher ventilation rates, especially during humid summer months, conventional chillers may not adequately control humidity. This is especially true with chillers that are controlled by a thermostat to cycle on and off to respond to building cooling load fluctuations.

As a result, desiccant systems have been developed for commercial building use. These systems have been used for over 50 years, originally developed for drying of process air for ship cargo, pharmaceutical manufacturing, film processing, and other applications. Industrial firms still depend on desiccants for these and other high value applications to dry process air. With the recent push towards building humidity control, manufacturers of desiccant systems have developed new packages designed to treat building ventilating air efficiently.

Desiccant systems incorporate desiccant materials, which absorb moisture from air. After a period of exposure to humid air, these materials become saturated, and require regeneration if they are to be reused. This regeneration is typically accomplished by exposing the desiccant material to heated air. Desiccant systems typically incorporate a desiccant wheel, which rotates between a stream of ventilating air (from which it removes humidity) and a stream of heated air (which regenerates the desiccant material). By rotating through these two streams of air, the desiccant wheel dehumidifies the ventilating air and rejects the moisture to the heated air stream. Desiccant systems become a part of a CHP system when they use the waste heat from the CHP system to provide regeneration.

Desiccant systems, by removing latent load from the ventilating air, can effectively reduce the amount of cooling necessary from the building chiller. There is a small increase in sensible load introduced, since the process heats the ventilating air before it is introduced into the building space. While some of the heating comes from "carryover" of the heat from the regenerative process, most comes from the latent heat of water being converted from a vapor to liquid as it is absorbed by the desiccant.

This added sensible load can be removed by directing the ventilating air through the building chiller, or by incorporating a recuperative heat exchanger or evaporative cooler. For the purpose of this study, however, the former solution will be applied. Desiccant systems also require electricity to drive the fans that create the airflow through the desiccant wheel. Even with these energy requirements, desiccants can be an energy efficient method of controlling humidity. By enabling control of latent loads without

expensive overcooling and reheating, desiccant systems offer much improved flexibility and energy efficiency.

Because desiccants serve air conditioning loads differently than conventional chillers, their capacity and efficiency are rated differently. System capacity is often expressed in volume of airflow (cfm), and sometimes in moisture removal rate (lbs/hr). Infrequently, a unit's capacity will be expressed in cooling tons, and in these cases, sensible tons must be differentiated from latent tons. Care must be taken when comparing these units with those of conventional chillers, since the desiccant unit performance varies with the conditions of the ventilating air and the desired control levels of the space being conditioned. Furthermore, the COPs of desiccant systems vary if evaporative or recuperative cooling is incorporated, and depending on the source of energy used for regeneration (i.e. direct-fired versus waste heat). One method of determining the performance of a desiccant system is to evaluate its effect on the conventional cooling system, in terms of displaced cooling load. Using this method, one can determine the effective capacity of a desiccant system as it relates to the entire building system. The cost and performance of desiccant systems is shown in Table 2-4.

Table 2-4. Cost and Performance of Desiccant Dehumidification Systems

SCFM	Cost ($/SCFM)	Thermal Input (hourly Btu/scfm)	Maximum Latent Removal (hourly Btu/scfm)
1500-5000	8-18	30-100	30-60
5000-10000	6-11	30-100	30-60
10000+	6-9	30-100	30-60

Section 3

MARKET POTENTIAL

To achieve widespread use in buildings, IES must treat the heating, ventilation, air conditioning, water heating, lighting and power loads as an integrated system, serving the majority of these loads either directly or indirectly from the CHP output. The market analysis used in this study examines the potential for IES when the system perspective is taken, and IES works as a building system that helps cooling needs, and not just as conventional CHP.

The analysis is performed using RDC's DIStributed Power Economic Rationale SElection (DISPERSE) model. This tool is a spreadsheet-based model that estimates the achievable economic potential for IES by comparing various options with traditional equipment. The DISPERSE model calculates fuel use, on-site electricity generation, electric and natural gas bills, installed cost, and economic return on investment for individual facilities. In this effort, the DISPERSE model was configured to analyze commercial buildings throughout the U.S. using load profiles that estimate cooling, heating, hot water, and electricity loads based on a number of different cities in the U.S., and simple payback was used as the economic decision measure.

As a result, this study was able to analyze IES performance on an hour-by-hour basis, examining the full range of building types, their loads and timing, and assessing how these loads can be technically and economically met by IES. Appendix A provides more details regarding the methodology and input data. The analysis was designed to examine both single buildings and multi-building facilities. Multi-building facilities were analyzed as one set of loads on a system that serves several buildings, each sharing the capital costs and the savings in energy costs. IES options analyzed for both single buildings and multi-building facilities include CHP with absorption chillers, and engine-driven chillers. In building types without central chilled water distribution systems, CHP only scenarios have been evaluated.

Before publication of the 1997 edition of the ASHRAE Handbook of Fundamentals (American Society of Heating, Refrigerating, and Air Conditioning Engineers), design professionals lacked data describing extreme (design) moisture load conditions. Cooling and dehumidification systems (typically air conditioning systems) are usually designed based on extreme (design) temperature conditions and fall far short of capacity when moisture really reaches its peak – usually at moderately warm temperatures. Thus, although it is felt that excluding waste heat-regenerated desiccant dehumidification as a function provided by IES in this initial market assessment is a reasonable representation of current building stock and conditions in the U.S., a follow-up assessment effort is planned. That supplementary assessment will include consideration of new ASHRAE design moisture data and ASHRAE 62-2000 ventilation standard requirements and will likely show penetration by IES/desiccant combination systems and, as a result, will increase the total market potential.

IES Compatibility With Buildings

IES systems were analyzed only for buildings with CHP-compatible utility service and distribution systems. Compatible utility service required both gas and electric service on-site. Heating distribution systems include district hot water/steam, boilers with hot water/steam, and furnaces with forced air distribution. For cooling systems, district chilled water or central chillers with chilled water distribution were addressed. Since CHP-only systems can be applied in buildings without chilled water distribution, the minimum criterion was buildings with electric and gas service. As shown in Table 3-1, 54 percent of building square footage in the U. S. has compatible utility service and distribution systems. Of the 46 percent that do not, 35 percent are eliminated due to lack of utilities (mostly availability of natural gas) and 11 percent have non-compatible distribution systems (mostly packaged terminal units).

Table 3-1. Buildings With CHP-Compatible Utility Service and Distribution Systems

	Million Sq. Ft.	% of Total
Total	58,772	100%
With electricity	57,076	97%
With electricity and natural gas	38,009	65%
With utilities and dist. System	31,611	54%
Hot water distribution system	7,756	13%
Hot and chilled water distribution systems	8,553	15%
Forced air distribution system	15,035	26%
Forced (hot) air and chilled water distribution system	267	0%
Non-compatible distribution systems	6,398	11%

Source: 1995 Commercial Building Energy Consumption Survey (CBECS), EIA

As shown in Table 3-1, buildings with forced air distribution were included as CHP compatible. This is based on integrating air-to-air heat exchangers into the system to recover the CHP waste heat and transfer the heat into the building distribution system. While this is not a common practice in building CHP systems, it is an option that is used in industrial systems and could potentially expand the base of buildings with IES, particularly smaller sites.

The Potential Building Market for IES

The analysis revealed that the potential building market for IES is over 35 GW by year 2020, including CHP with absorption chillers, engine-driven chillers, and CHP-only systems for buildings without chilled water distribution. This market potential is based on achievable economics, where the IES option provides a minimum payback of 10 years compared with conventional HVAC systems and grid purchasing using an economic analysis described in Appendix A.

As shown in Table 3-2, this potential includes both system turnover in existing buildings, as well as IES in new buildings. Included in this market is a significant potential for new absorption chillers (8.9 million tons), thermal storage (3.2 million tons), and engine driven chillers (2.4 million tons). Together, if implemented this market potential would represent almost 18 million metric tons of reduced carbon dioxide emissions (based on carbon equivalent) annually by the year 2020, and would contribute significantly to meeting the goals originally established by the Kyoto Protocol. This reduction in carbon emissions is based on displacing grid emissions from average U.S. utility plants.

Table 3-2. Building Market Potential for IES

	2010		2020	
	Turnover	New	Turnover	New
Capacity (GW)	10.4	6.5	19.0	16.5
Displaced Electricity (GWh)	66,900	45,800	133,900	117,100
Capital ($million)	6,380	4,150	12,750	10,430
Incremental NG Use from CHP(Tbtu)	550	380	1,090	960
Boiler Fuel Displaced (Tbtu)	90	60	180	170
Absorber (1000 tons)	3,310	2,340	6,630	5,860
Storage (1000 tons)	740	670	1,480	1,730
Engine Driven Chiller (1000 tons)	630	470	1,260	1,180
CO2 Displaced From Utility (MtC)	12.1	8.3	24.3	21.2
MtC Produced By Incremental NG	7.9	5.4	15.8	13.9
CO2 Displaced from Boiler (MtC)	1.8	1.2	3.5	3.3
CO2 Displaced (MtC)	6.0	4.1	12.0	10.6

Note: Boiler fuel displaced is net of additional natural gas required by absorption units during peak cooling periods to supplement thermal output from CHP units.

This market potential, when compared to the estimated IES capacity of 3.5 GW currently installed, yields a current penetration level of less than 10 percent. Increasing market penetration to 50 percent levels would add over 14 GW of capacity, but would first require significant lowering/removal of the many barriers that exist (see Section 4).

The system turnover analysis was accomplished by assessing the existing base of buildings, and applying IES as their convention systems (i.e. boiler and electric chiller) require replacement. Over the 2000-2020 timeframe, the entire existing base of buildings was projected to turn over, with a portion of the buildings requiring systems replacement each year over the 20-year period. The building turnover market potential was estimated at approximately 19 GW. The load profiles used for the system turnover analysis assumed a vintage stock of building equipment, including less efficient envelope and other building systems.

The new building analysis applied forecasted rates of building construction to the existing base of buildings, and evaluating these buildings for IES. Assumptions were made that the mix of distribution systems used in a particular region would be also used in the new buildings constructed in that region. Assessing the forecasted growth in buildings on a regional basis, again using local utility rates and gas prices, as well as load profiles for each building type, the analysis found a potential market of 16.5 GW for new buildings. For the new building analysis, the load profiles assumed a new, more efficient envelope and other building systems.

The market potential includes analysis of both single-buildings and multi-building facilities. Single buildings were analyzed by evaluating a full range of conventional systems and IES options including absorption units and engine driven chillers. For both conventional systems and IES a variety of system operating strategies were employed, using storage as well as baseloaded and peaking chillers (see Appendix A for details). Both engine- and turbine-based IES were evaluated, using systems sized based on the building size, and ranging from small spark ignited gas engines and microturbines to large turbines.

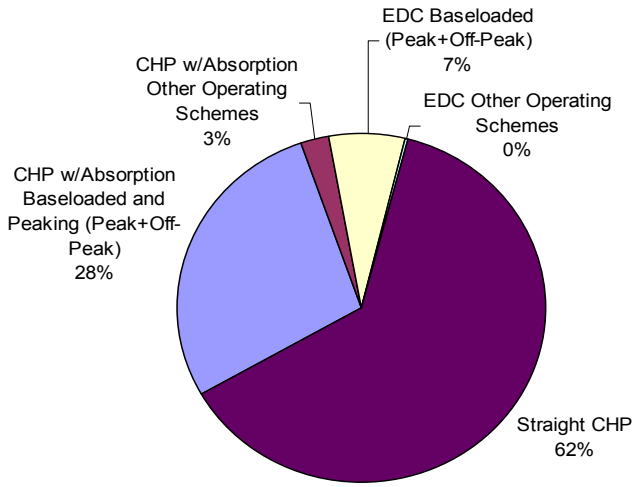


Figure 3-1. Distribution of IES Market Potential by Cooling Operating Scheme

The results indicated that each cooling option had a unique operating scheme that offered the best economics. For CHP with absorption chillers, operating the chiller to serve both baseload and peak loads, as well as operate on-peak and off-peak made the most sense. This was compared to using the absorption unit for peaking only, baseload only, and examining on-peak only operation as well as using storage for peaking operation. Considering all of these options, 92 percent of the cases where absorption made sense were for absorption serving the entire cooling load (28 percent overall). Engine-driven chillers had better economics when baseloaded during both on-peak and off-peak periods, using an electric chiller for peaking. Again, options for using the EDC full time, as well as using storage or using the EDC only during peak periods, were examined and the baseloaded scheme was the most economic. A major reason for this difference is that, other than for the smaller sizes, EDCs tend to be more expensive to install and operate than single-effect absorption units, so baseload operation makes more sense.

Figure 3-2 shows that the market potential is spread relatively evenly among the new/single building, turnover/single building, new/multi-building, and turnover/multi-building markets.

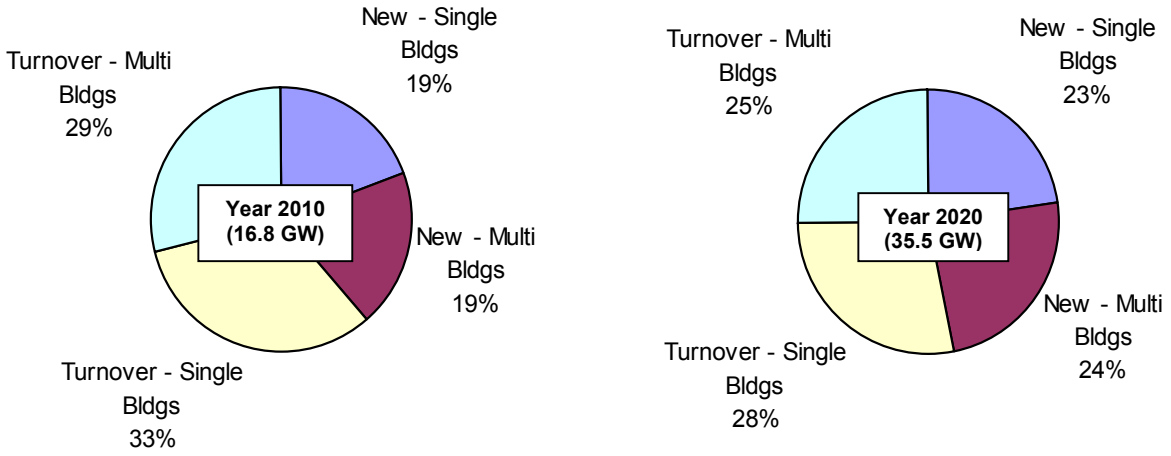


Figure 3-2. Market Potential for Single Buildings and Multi-Building Facilities in 2010 and 2020(GW)

In 2010, the turnover market is larger, with the single building market the biggest portion. In 2020, this remains the case, but with both new building markets taking a larger share. This is due to the relatively constant turnover in existing building systems throughout 2000-2020, compared to the new buildings that have been forecasted to be added at a faster rate in the 2010-2020 timeframe.

The multi-building analysis again evaluates a full range of IES options against the conventional options, but also includes a set of central IES options that would enable the building to invest in a central IES and share in the energy savings. For this analysis, multi-building facilities (MBFs) in urban areas (required for density to decrease costs of connecting buildings with chilled water and hot water/steam distribution piping) were evaluated. These options were designed for groups of multi-building facilities to share a system that would serve a "virtual" campus of buildings, targeted at 1 million square feet. These buildings were then evaluated by including the option to purchase a portion (based on their square footage) of the MBF system, and share in the operating cost and output on this basis. For MBFs that did not possess the suitable building heating or cooling distribution system, these buildings were given the option of CHP only (for those with suitable heating distribution) or installing suitable distribution systems.

Table 3-3. Breakdown of Market Potential by Distribution System (MW in Year 2020)

Building Type	Bldg Distribution		Heating/Cooling Loop		IES Market Potential				
					On-Site			Central	
	Heating	Cooling	Heating	Cooling	CHP Only	CHP w/Absorber	EDC	CHP Only	CHP w/Absorber
Single Bldg	Hydronic	None	NA	NA	1,700	-	-	-	-
	Hydronic	Hydronic	NA	NA	1,300	3,200	1,700	-	-
	Forced Air	Hydronic	NA	NA	-	100	100	-	-
	Forced Air	None	NA	NA	4,000	-	-	-	-
Multi Bldg	Hydronic	None	None	None	800	-	-	1,700	-
	Hydronic	None	Yes	None	100	-	-	500	-
	Hydronic	Hydronic	None	None	2,200	2,100	600	300	600
	Hydronic	Hydronic	Yes	None	300	300	-	5,700	200
	Hydronic	Hydronic	Yes	Yes	-	100	-	3,500	4,000
	Hydronic	Hydronic	None	Yes	-	-	-	-	300
TOTALS					10,461	5,820	2,443	11,664	5,014

Figure 3-3 illustrates the types of IES that represent this market potential. CHP-only systems are by far the most representative, with 22 GW in potential. This large share is primarily due to the base of buildings (both single buildings and multi-building facilities) that possess hot water/steam or forced air distribution systems but do not have chilled water distribution. This base of buildings, as shown previously in Table 3-1, is almost two-thirds of the base of buildings that have gas and electric utility service. Further assessment could determine the potential for distribution of small heat activated air conditioning throughout buildings with hot water or steam loops and no chilled water distribution systems

Another contributor to the CHP-only market is the base of smaller buildings. For smaller buildings, the additional cost for CHP with absorption chillers is high compared to CHP-only systems due to the relatively high cost of indirect-fired absorption units in the under 100 ton range. The larger buildings that have both suitable heating and cooling systems offer a potential of 11 GW of CHP units with absorption cooling systems, and an additional 2 GW of engine-driven chillers make up the remainder of the IES. The recent development of direct exhaust gas power absorption chiller technology in the 500 ton range provides an important cost reduction for IES which will further reduce the economic payback time of these systems.

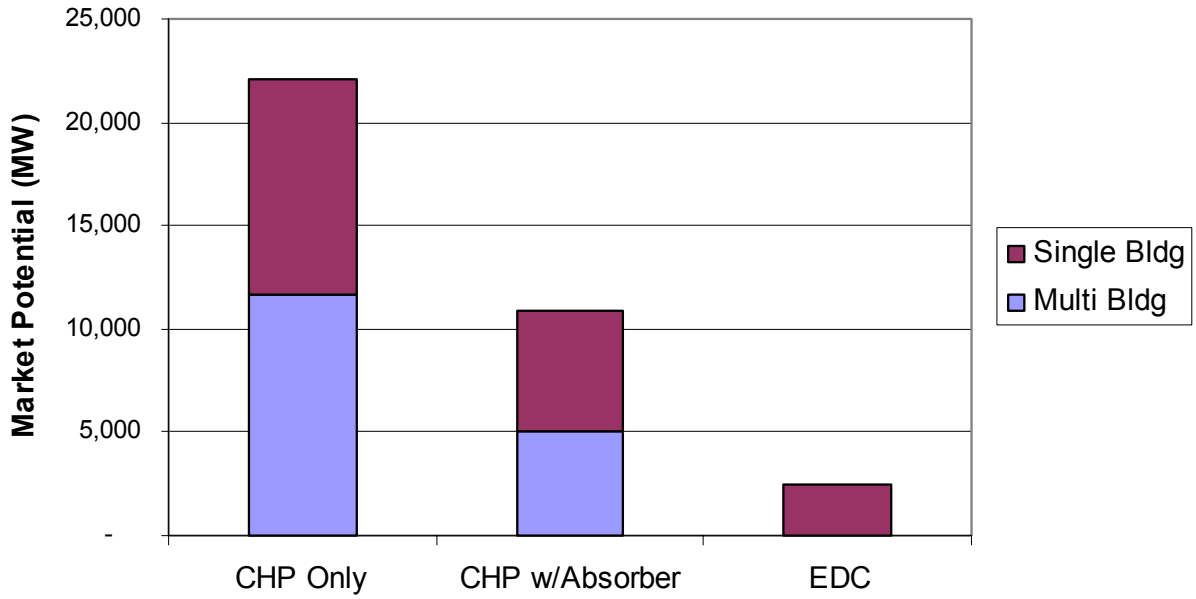


Figure 3-3. Distribution of Market Potential Among Variations in IES

As previously discussed, the buildings are analyzed with load profiles based on controlling humidity at 60 percent relative humidity levels. This control, however, is not strictly in compliance with ASHRAE 62-2000, and thus does not use high levels of reheat. As a result, technologies such as desiccant dehumidification could have an important effect on future market potential.

A wide range of IES unit sizes is represented in the potential market. Units from 30 kW on up to over 10 MW were evaluated for IES applications, including both engines and turbine prime movers. As shown in Figure 3-4, the dominant size ranges are between 30 kW and 500 kW, representing over 45% of the potential. Within these size ranges, spark-ignited natural gas engines hold an edge over turbines due to their higher electrical efficiency and competitive installed cost. A small number of microturbines emerge in the 100-500 kW sizes, and in the larger sizes over 1 MW, more turbines emerge as these systems are designed for larger applications such as industrial or multi-building facilities. In larger sizes, the difference in electrical efficiency between engines and turbines narrows, and the overall efficiency edge offered by turbines allows them to gain market potential. A number of these larger IES systems already exist in universities throughout the U. S.

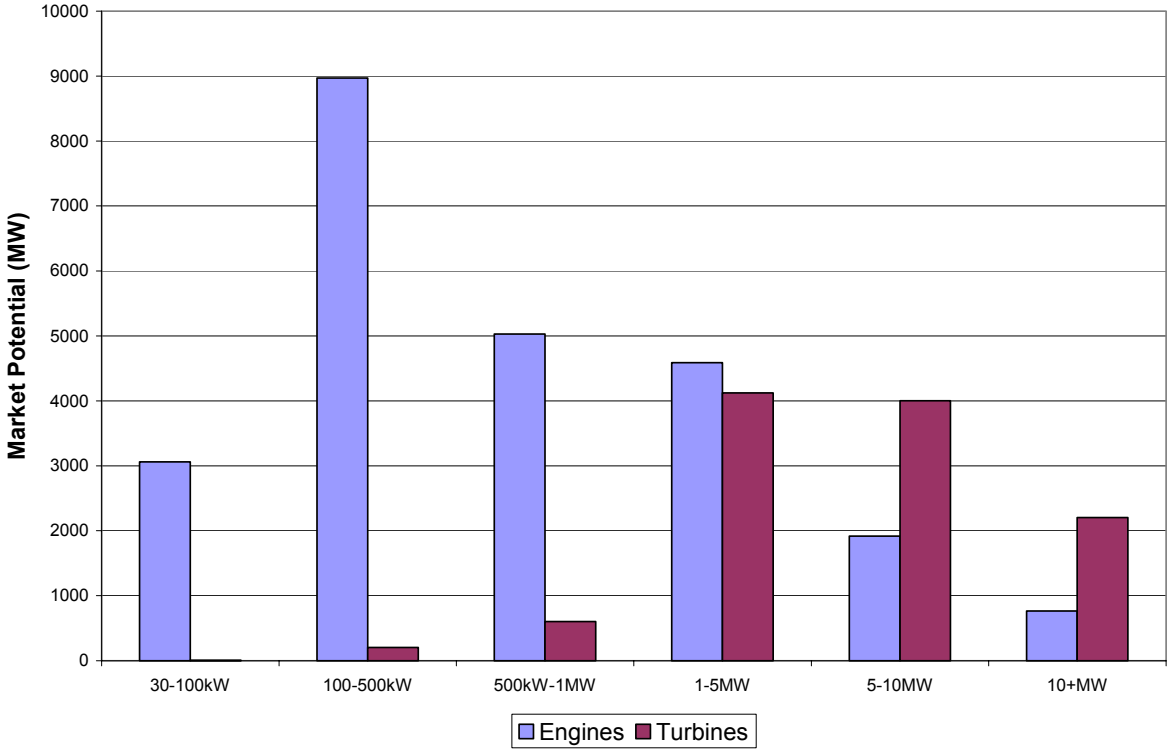


Figure 3-4. Market Potential for IES by Size and Type of CHP Prime Mover

Analysis of Building Types

To date, most IES is concentrated in education and health care buildings. The education sector includes universities, which have long used CHP as a means of controlling utility costs. While some barriers still exist in this sector, such as the price of backup power and the regulated market for surplus power, other barriers such as first cost have not been factors in CHP market penetration. Similarly, hospitals have a smaller but still significantly large installed base of CHP, and lodging has a small base of applications.

For other building sectors, the economics of IES holds promise, but barriers prevent widespread adoption. As shown in Figure 3-5, the potential for IES is highest in office buildings, with over 10 GW of total IES, including significant opportunities for CHP with absorption units and engine-driven chillers (45 percent of the office potential). Of that 4.5 GW, CHP with absorbers represent over 3.6 GW and EDCs 1.1, giving offices almost half of the total EDC potential.

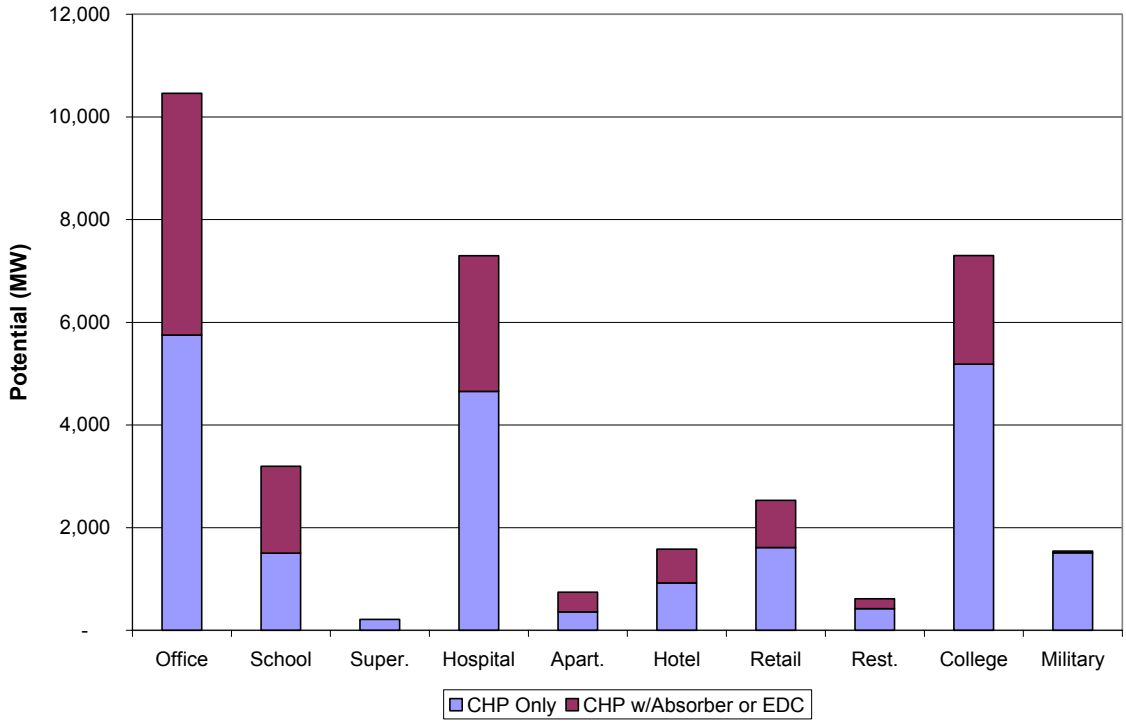


Figure 3-5. IES Potential by Building Type

Hospitals and colleges, while already established in the CHP use, each offer over 7 GW of potential for IES, respectively. Schools, retail, and hotels are smaller segments, but with their significant heating and cooling loads offer additional IES potential plus opportunities for absorption units and EDCs. Schools and apartment buildings offer the highest share of CHP with absorbers or EDCs, constituting over half of the total IES potential for that building type.

Military bases and supermarkets, offer potential for IES, but not much for absorbers or EDCs. Supermarkets tend to lack chilled water distribution systems, and military bases do not generally have base-wide cooling distribution systems.

Regional Analysis

The economics of IES is driven largely by the relative gas and electric prices. Portions of the U.S. where low gas prices and/or high electric prices prevail often offer good conditions for IES, and areas where both high electric and low gas prices offer ideal conditions. Figure 3-6 illustrates the electric and gas prices using a term coined in wholesale energy markets: "spark spread." Spark spread is defined as the difference, or spread, between grid electricity prices and the fuel cost necessary to generate electricity using natural gas.

Figure 3-5 illustrates the "spark spread" for IES across the U.S., using a typical natural gas engine as the generating option. This figure shows that the top states for IES potential offer over

6 cents per kilowatt-hour spread, primarily due to high electric rates, and include Alaska, California, New York, New Jersey, Vermont, and New Hamshire. Not coincidentally, most of these top states (excluding Alaska) have made significant progress towards electric industry restructuring. Other states in the New England, Middle Atlantic, Mountain, West South Central, and East North Central offer attractive IES spreads in the 4 to 6 cents per kilowatt-hour range.

These "spark spreads" help explain the regional distribution of IES potential. Figure 3-7 presents a regional distribution of the IES potential:

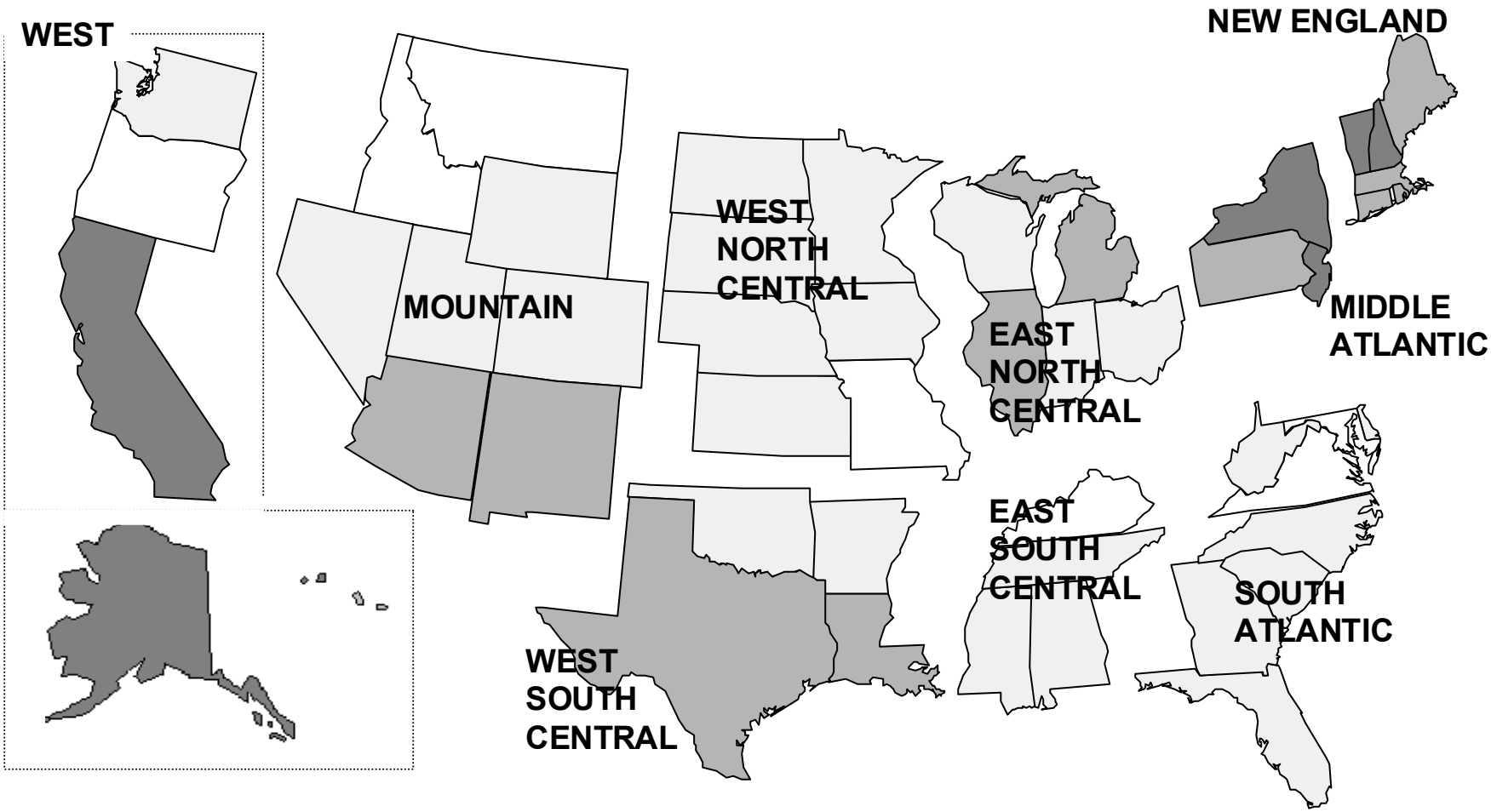
- The Pacific region, dominated by the a large building population, high electric prices and intensive cooling loads in California, offers the most IES potential. This region also offers the most potential for CHP with absorption or EDCs. There is some CHP-only potential due to still significant heating loads.

- The Middle Atlantic and New England regions each have a significant share of the IES potential, based on reasonably favorable spark spreads coupled with generally adequate cooling loads. These regions, also due to the favorable spark spreads, offer a major portion of the CHP-only potential but offer a lower percentage of the CHP with absorption or EDCs. The West North Central region also follows this pattern, but on a smaller scale due to less favorable spark spreads.

- The South Atlantic, West South Central, and East North Central regions, surprisingly, offer a balance between CHP with absorption or EDC cooling (about 40-45 percent of the total) and straight CHP (about 55-60 percent). The spark spreads here are marginal, in general, but some states (TX, IL, and MI) offer somewhat attractive energy prices for IES.

- East South Central and Mountain regions, with some intense cooling loads and generally low gas prices (although not the past two years), have the highest percenage of CHP with absorption or EDCs of any region. New Mexico and Arizona offer particularly strong energy prices for IES. Relatively small heating loads (on a regional basis) in these areas contibute to a small CHP-only potential.

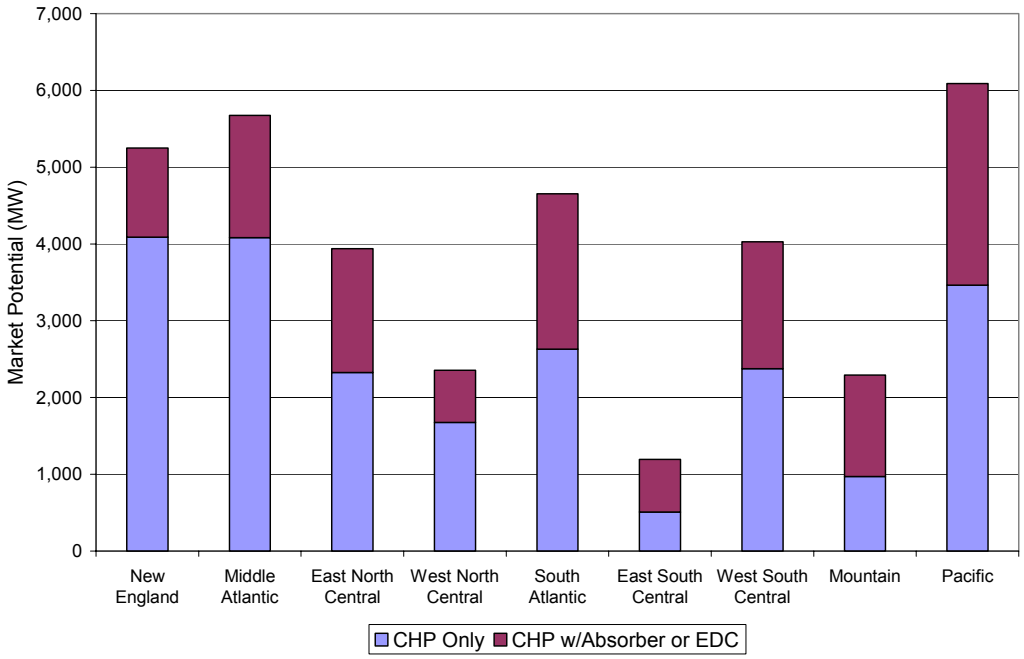
Figure 3-6. IES "Spark Spreads", by State



Source: Spark spreads calculated by subtracting the fuel component of electricity generation (average natural gas price from EIA's Natural Gas Monthly times the heat rate of a natural gas engine) from the average electricity price (from EIA's Electric Power Monthly).

- > $.06
- $.04 - $.06
- $.02 - $.04
- < $.02

Figure 3-7. IES Market Potential by Region



Sensitivity Analysis

A number of scenarios were constructed to evaluate how sensitive the base case is to varying inputs. In doing so, there was a focus on how improving the cost and/or the efficiency of IES impacts the market size. In addition, three sensitivities were added to illustrate the effects of changing energy prices on the IES market for buildings.

As shown in Table 3-4, 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+), and are documented in Tables A-1 and A-2.

Table 3-4. 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 scenarios involved changing energy prices. As shown in Figure 3-8, natural gas prices increased dramatically in late 2000 and through 2001, which was not reflected in the base case gas prices. As a result, 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.

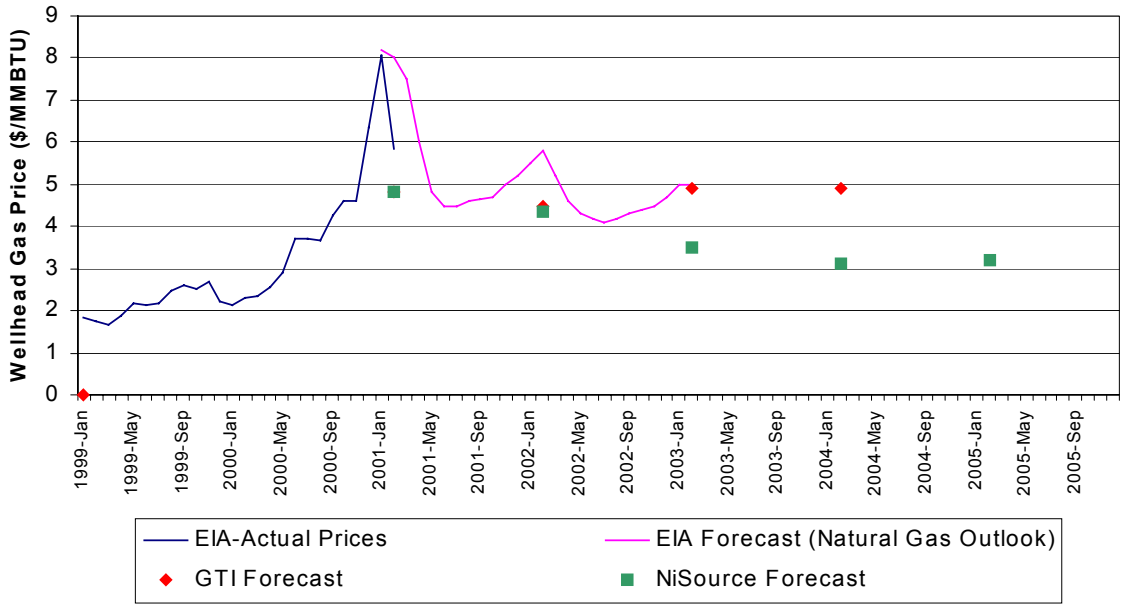


Figure 3-8. Natural Gas Price Increase (Through March 2001) and Industry Forecasts

Since it is generally accepted that there is convergence in gas and electric prices, translating the effect of high natural gas prices on commercial building 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 that cost to the amount of electricity generation to derive an updated electricity price. This method is similar to how utilities calculate their fuel adjustment clause (FAC).

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 expectations of future prices, but simply to examine the impact on the IES market in buildings should either scenario emerge.

In addition, a final price scenario (Peak FAC) was added to see how the buildings market for IES would be affected if the increase in gas prices was reflected solely as a demand-based charge. While this value would ultimately be likely 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 $/kW charge 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 3-9) indicate that improvement in the installed cost and efficiency increases the market size dramatically. Both future scenarios increase the potential market from 35 to almost 70 GW, nearly doubling the market size. The results show that reducing the installation cost has some effect, but the major increase is primarily due to realizing the improvement in cost and efficiency that is expected in the future scenario.

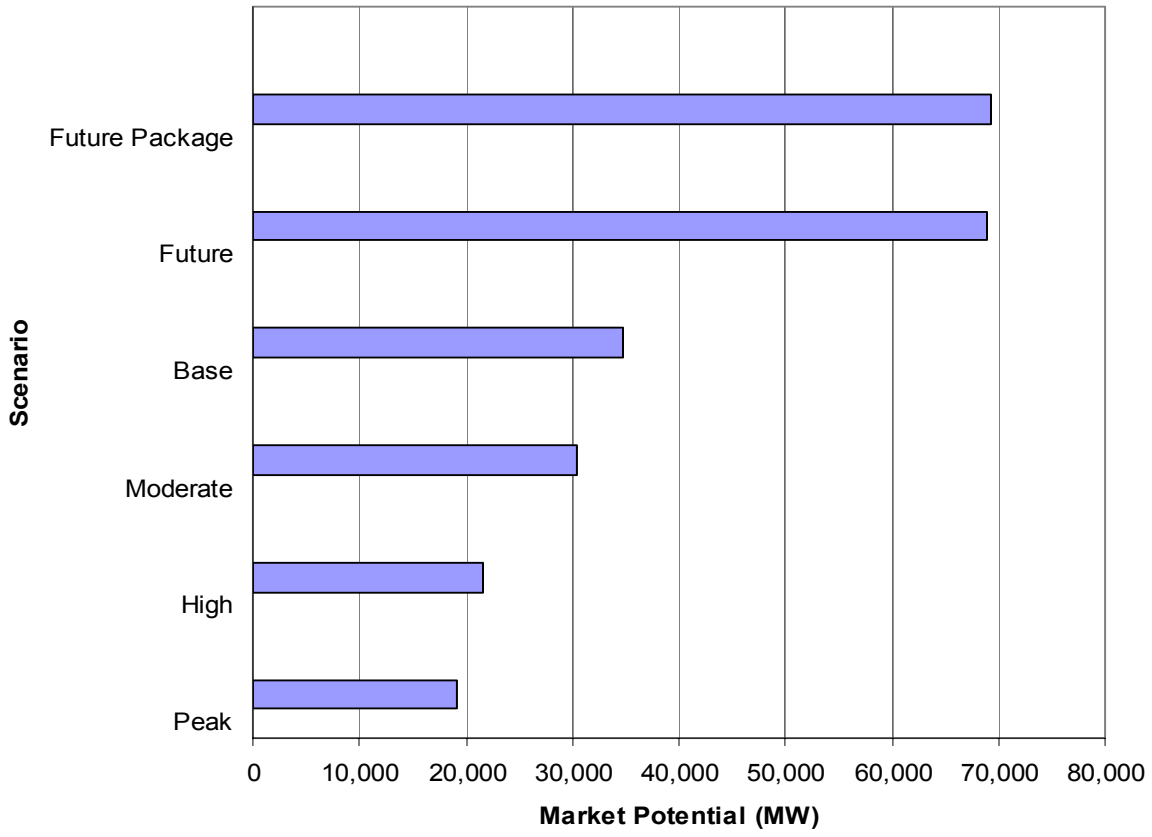


Figure 3-9. Future Scenarios Offer Highest Market Potential

The price sensitivities tell another story. On the surface, it appears that higher energy prices lead to less potential for IES. Figure 3-10 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.

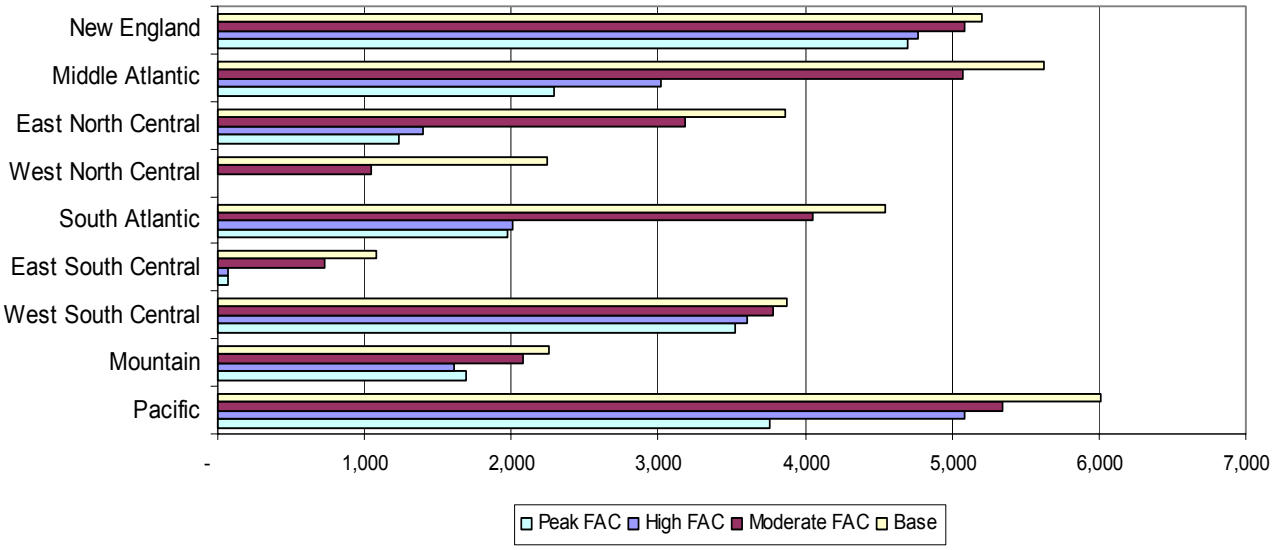


Figure 3-10. Regional Effects of Price Sensitivities on IES (MW)

The major factor driving this decrease in market potential is the combination of high electricity prices and use of thermal energy, as the economics of IES in general improve with high prices if the thermal utilization is high. Figure 3-11 supports this supposition, with the CHP-only configurations offering improved market potential with high energy prices in regions of the country where the share of gas-fired generation is high, such as the Pacific, Mountain, West South Central, and New England. In these regions, the prices of electricity and gas tend to move together, with electric prices increasing significantly as gas prices rise. Other portions of the U.S., such as the East North Central, West North Central, East South Central, and South and Middle Atlantic have more coal and nuclear generation, and thus are less affected by rise in gas prices. Current IES performance tends to be penalized in these portions of the country when gas prices rise. However, this trend may chance as many new intermediate duty and peaking plants are natural gas turbines, a fact which will change the future dynamics of this marketplace.

Where CHP is used with absorption cooling or engine driven chillers, the use of thermal energy becomes less important and the market potential drops in high price scenarios. In the case of CHP with absorption, the most economic use of absorption tends to be using the absorber to serve the entire cooling load, and requires additional natural gas to fuel its operation. This purchase of additional gas, while economic, tends to become less so when gas prices increase.

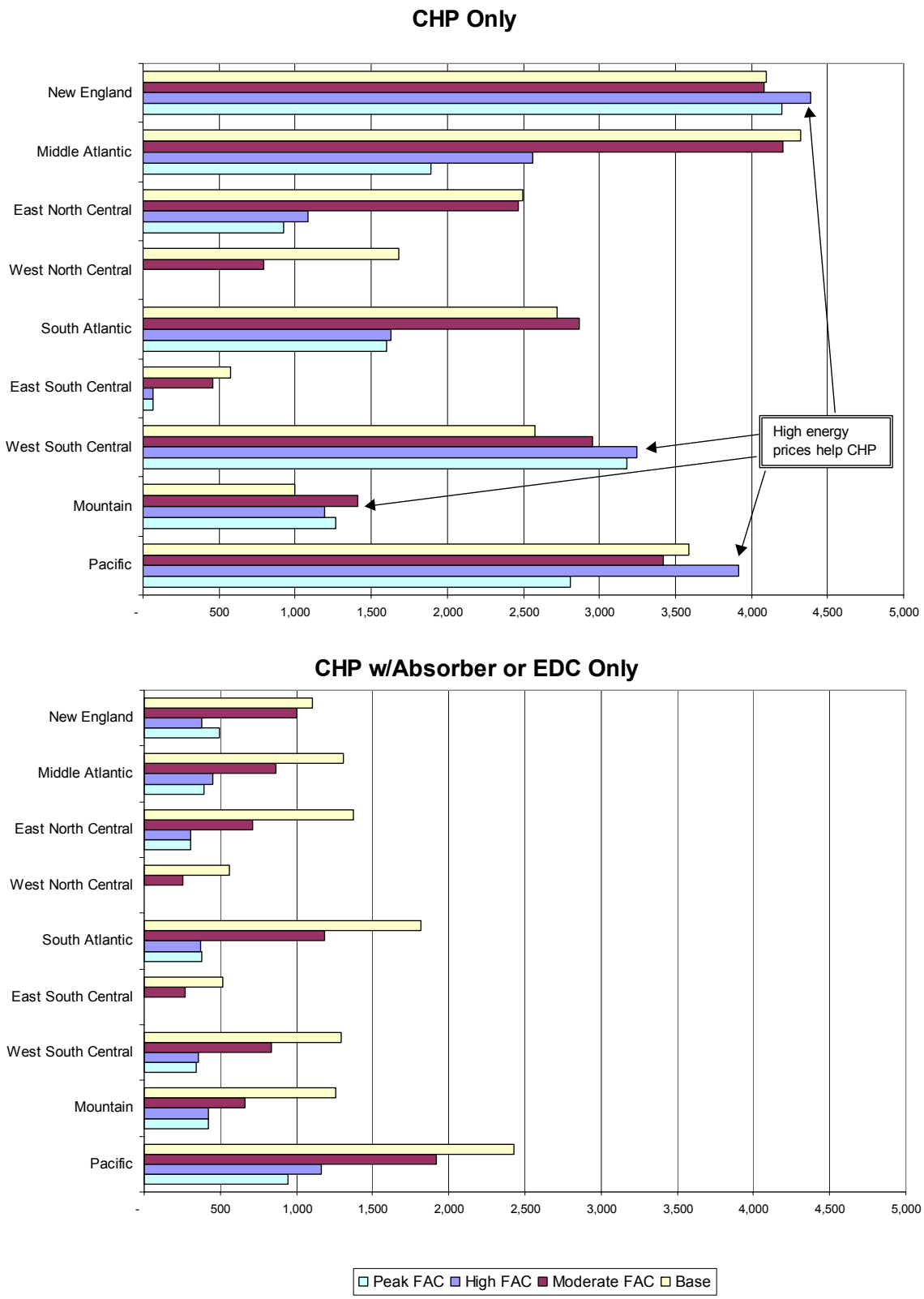


Figure 3-11. Regional Effects of Price Sensitivities on IES (MW)

Section 4

TECHNICAL AND MARKET BARRIERS

Despite improving economics, increasing emphasis on overall energy efficiency, and concerns over restructuring of the electric utility industry, IES systems face an uphill battle for acceptance in the building market. A number of barriers stand in the way of realizing the benefits inherent in implementing IES on a wide scale, and applications in the U.S. buildings sector are currently limited due to 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 an IES project uneconomic, and can frequently present such a confused and uncertain option to potential end users that more traditional HVAC and purchased power approaches are favored. Table 4-1 identifies examples of each of the barrier categories.

Table 4-1. Market and Technical Barriers to IES for Buildings

Category	Example Constraint
Economics and Tax Treatment	Lack of available tax credit to help defray capital cost; treatment as 39-year property under current tax laws
Product Performance and Availability	Lack of integrated systems; inability of systems to be applied to majority of building space served by non-IES compatible distribution systems
Awareness, Information and Education	Limited understanding of range of benefits associated with IES and thermally-driven cooling technologies within the building design community
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 IES projects
Environmental Regulation	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	Manufacturers focus on sales of conventional non-IES technologies, unwillingness to invest additional effort to sell IES options even when favorable economics are achievable

A number of forces are driving the building sector interest in IES technologies. Electric industry restructuring is opening the door to new business arrangements and non-traditional suppliers, and customers in increasing numbers are taking the lead in meeting their ultimate energy requirements. The pace of this change, and the degree to which the benefits of IES are realized,

depends on the ability of all stakeholders to overcome the barriers to its implementation. Each category of barriers is discussed in detail below.

Economics and Tax Treatment

Many building owners make their decisions on the basis of first cost, and IES options tend to cost more initially than conventional alternatives. As a result, the vast majority of buildings do not include IES systems even when life-cycle economics are favorable. Therefore, first cost remains a large barrier. One trend that is emerging to help overcome this barrier is the willingness of third parties to invest in IES. A number of utility subsidiaries, along with industry leaders such as Trigen Energy, are proactively searching for such opportunities, and providing building owners with many of the economic benefits of IES or conventional CHP systems without requiring the upfront capital investment.

Furthermore, aggressive leasing companies are offering leasing options that would allow building owners to effectively purchase IES systems without any capital outlay. Such leasing options are widely accessible to schools, hospitals, municipal governments, and federal buildings. It remains difficult for office buildings to obtain leasing opportunities due to their often diluted ownership structure (i.e. limited partnerships with highly leveraged properties).

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% DB	5-10 yrs		200% DB
For Sale to Others	Separate Project		Part of Structural Components of Building		
	Cost Recovery Period	Depreciation		Cost Recovery Period	Depreciation
	15 or 20 yrs	150% DB	Non-Res	39 yrs	SL
			Res	27 ½ yrs	SL

Product Performance and Availability

While IES systems have been available for years in sizes that apply to commercial buildings, 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 to a building IES. Though the market for absorption chillers has been growing, there is still considerable resistance, however, in the building design community to consider these units as viable options to compete with electric chillers.

Similar resistance confronts both engine driven chillers and desiccant dehumidification units. Engine driven chillers, 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 these maintenance activities, this remains a barrier to more widespread adoption. EDCs are, however, making headway in markets where their economics are strong. Concerns over reliability of desiccant units, while based largely on unfamiliarity with the technology, remain an obstacle.

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 are still being developed as field experience grows. Maintenance cycles are being recommended by manufacturers (e.g., 5,000 hours for microturbines), but are not yet proven in operating practice, and synchronization of maintenance requirements for the turbine components and the gas compressor still needs to be accomplished. 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 the life of these stacks is between 15,000 and 20,000 hours with fuel cell power output degrading 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 solid oxide fuel cell, with an estimated stack life of up to 5 years, may help minimize this constraint.

Awareness, Information and Education

The building design 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, building owners and design professionals will often stay with grid purchased power, typically not realizing the full value of the IES benefits. Further exacerbating this situation, and contributing to rather than breaking down the cost barrier, is the building sector's frequent focus on capital cost versus life-cycle cost.

Desiccants suffer from these issues, and from a lack of understanding of how they are specified. Because desiccants serve cooling loads differently than conventional chillers, their capacity and

efficiency are rated differently. System capacity is often expressed in volume of airflow (cfm), and sometimes in moisture removal rate (lbs/hr). Infrequently, capacity will be expressed in cooling tons. Care must be taken when comparing these units with those of conventional chillers, since the desiccant unit performance varies with the conditions of the ventilating air and the desired control levels of the space being conditioned. Furthermore, the COPs of desiccant systems vary if evaporative or recuperative cooling is incorporated, and on the source of energy used for regeneration (i.e. direct-fired versus waste heat). There exists a major uphill learning curve to be tackled before the building design community embraces this technology.

The integration of IES into building systems and with the grid requires that a new series of application know-how and empirical data be developed and transferred to building owners, architects, consulting engineers, contractors, policy makers, regulators and code officials. There is also a need to better match coincident electric and thermal loads with IES system capabilities, resulting in part from this lack of application and integration knowledge.

Utility Policies and Regulation

Many utilities have instituted backup power rates that add substantial costs to CHP applications. While these rates may accurately reflect the higher cost of "reserving" capacity for these part-time customers, they act as a barrier to implementation of IES 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 these cases, the utility does not accept 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 building owner, 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.

As electric industry restructuring begins to make its way across the country, building owners who choose to leave the grid of the local energy supplier may be 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 building owner with these exit fees and competitive transition charges is a disincentive to project implementation. While there are issues regarding the legitimacy of these costs, such as new IES owners claiming they had notified the utility far in advance of their intent to install their systems, there are real costs to the utility and other ratepayers should be required to subsidize IES. 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.

Another impact of electric industry restructuring on IES is the emerging practice by electric utilities of charging building owners for installation or upgrading electric service which dramatically increases the cost of installing electric devices that effect peak demand like electric air conditioning. While this is actually a barrier to upgrading conventional electric systems and can have a positive impact on IES, it is nonetheless a trend that should be monitored.

Planning, Siting and Zoning

IES is 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 a building, 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 will require time to get necessary approvals. Delays due to this process can be quite frustrating to building owners, and may result in abandoning IES projects. Having project developers experienced in both IES and working with the local contractors can be a big plus in terms of getting the project done.

Environmental Regulation

IES 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 IES 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 line losses, and taking possible advantage of IES applications. Recent EPA guidelines for output based standards would help IES units immeasurably, but it remains to be seen how states act on these guidelines in their State Implementation Plans (SIPs).

Emissions control technologies are being approved as meeting emissions limits, but 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 BCHP or ICHP 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 IES options.

Supporting Market Infrastructure

Both reciprocating engines and combustion turbines have extensive dealer and service networks available, 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 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.

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 who, as the "tried and true" alternatives require less intensive sales efforts, tend to follow the path of least resistance in their marketing efforts. As more consulting engineers and other design professionals gain experience with absorption units, an increase in requests for these units will likely boost sales, and therefore raise the visibility of these products within their parent organizations. As the market grows, the sales efforts should intensify.

One major challenge faced by IES is the lack of integrated systems. Finding the optimal CHP components that, when integrated, can meet the wide range of building heating, cooling, and electric loads is left up to the building owner and their supporting design professionals. Engineering and field integration of individually designed pieces of equipment requires high quality engineering and high cost labor, both of which are in short supply and are expensive. Until many competitively priced, integrated IES packages are available, the buildings market for IES will continue to be underdeveloped.

Section 5

TECHNOLOGY R&D IMPLICATIONS

The results of this study show that if IES and cooling technology improve as assumed in the future scenarios, then the buildings market would double in size. For IES to realize this potential and compete with conventional options, a number of technology improvements are needed for both CHP systems and IES cooling 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 in a range of areas.

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 10-40 percent improvement in electrical efficiency. These assumptions are (see Table 5-1), however, 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 IES market potential, as even modest cost reductions (i.e. 5-10 percent) will result in the market growth.

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 R&D focused on reciprocating engines is designed to increase efficiency or lower 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, inability to use three-way catalysts to reduce emissions, and a lower power to volume ratio. 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 on 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 than from rich burn options, research on new types of catalytic emissions reduction is needed to achieve lower emission levels so these engines can 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 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% efficiency, 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. Microturbines typically employ a single shaft which leads to simplicity and ease of mass production, which will be 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 also 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 to the reliability of support systems such as pumps and fans needed for operation and therefore improvements in these areas would increase the attractiveness of fuel cells. Future research and development into microturbine/fuel cell hybrids is also expected.

For fuel cells currently under development the major obstacle is cost. The one current commercial offering costs over $3,000/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 buildings with forced air distribution are needed. The study results indicate that 4 GW (over 10 percent) of the base potential and over 25 percent of the buildings market are served by forced air distribution. Hot air systems have been used in the industrial sector for processes such as drying, and likely have some applicability in the buildings sector. There are differences in the temperature of these applications relative to building needs that would affect the design and materials, so they are far from market ready.

Improving IES Cooling Options

While CHP systems have been available for years in sizes that apply to commercial buildings, the performance and availability of thermal-driven cooling technologies have been barriers to widespread application of these technologies in stand-alone configurations, much less as a component to a building IES.

As a result of several of the largest U. S. chiller manufacturers offering absorption units, costs have been reduced, lead times lessened, and availability improved. These in turn have boosted the domestic market for absorption chillers. The study results indicate almost 11 GW of CHP with absorption, accounting for over 30 percent of the base case market potential, growing to nearly 20 GW in the future scenario. This growth in potential is based largely on the drop in installed cost of single-effect absorption units, assuming a 15-30 percent drop in larger units and up to 65 percent 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.

In addition, IES would benefit from a closer match between absorber heat requirements and thermal output available from CHP units. The study revealed that the leading absorption option was sized to meet the entire cooling demand of the building, and typically required supplemental firing with natural gas to do so. The application of double effect absorption units, although not considered in the study since smaller CHP units (i.e. recuperated microturbines and reciprocating engines) do not generate thermal output of sufficient quality (generally 350°-400° F), is needed. It is possible to use larger CHP units, particularly turbines, to supply double effect absorbers, as well as to use supplemental firing to boost the thermal quality of smaller CHP units to meet the needs of double effect units. Neither of these cases was considered in the study, but could be evaluated in the future.

Another option that would help provide better balance between thermal 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, 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, and some of these programs apply 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 building cooling loads.

Other potential limitations of the study that affect IES cooling options include the lack of heat recovery considered for engine driven chillers, and strict control of building humidity levels to comply with ASHRAE 62-2000-. As a result, technologies such as desiccant dehumidification could have an important effect on market potential. Should future efforts examine these issues in more detail, recommendations for improving these technologies to boost IES potential for buildings could be developed.

Improving the IES Package

One major challenge faced by IES is the lack of integrated systems. Finding the optimal IES components that, when integrated, can meet the wide range of building heating, cooling, and electric loads is left up to the building owner and their supporting design professionals. In response to the recent DOE solicitation, seven industry teams have announced research, development and testing of "first generation" integrated CHP and absorption chillers with controls, some with desiccant units as well. This program holds promise for the buildings market for IES, offering multiple benefits, including lower integration costs and risks. However, even if these efforts result in several market-ready systems, they will be but a few variations of the dozens the market will require. Until many competitively priced, integrated IES packages are available, the buildings market for IES will continue to be underdeveloped. It is, however, a strong step towards establishing widespread IES in the buildings sector.

Appendix A
METHODOLOGY

Analyzing the potential market for IES in buildings 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 IES application.

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

Market Assessment

The analysis of IES for buildings 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.

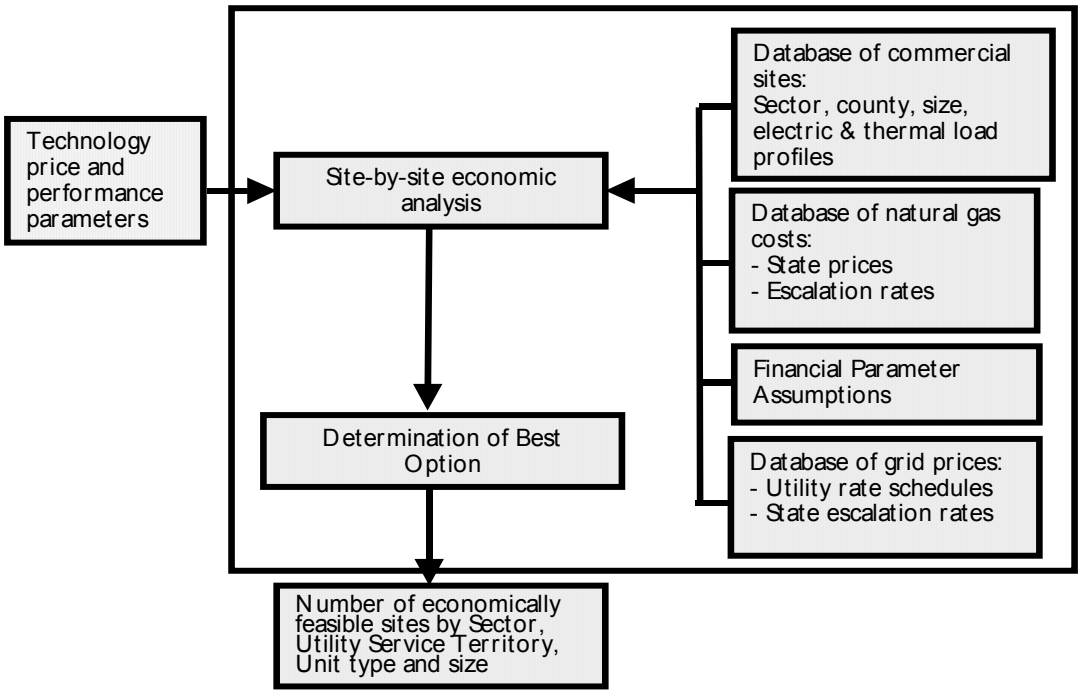


Figure A-1. DISPERSE Model

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/building 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 the 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) 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, including one scenario where the installed cost of absorption cooling options is reduced by cutting the installation cost in half. This scenario was created to reflect the results of R&D efforts underway to reduce the installed cost of CHP/absorber packages.

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 is 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+)				Future Technologies w/Package Cost Decrease(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)	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	641	0.95	0	48
	Reciprocating: Air Cooled	625	1.4	0	60	594	1.3	0	57	594	1.3	0	57
	Absorption: Single Effect	1100	0.0	17	70	445	0.03	16	67	392	0.03	16	67
	Engine Driven	950	0.02	11	80	891	0.02	10	76	891	0.02	10	76
50-100	Reciprocating: Water Cooled	650	1.0	0	35	618	0.95	0	33	618	0.95	0	33
	Reciprocating: Air Cooled	600	1.3	0	50	570	1.2	0	48	570	1.2	0	48
	Centrifugal	675	0.8	0	40	641	0.71	0	38	641	0.71	0	38
	Absorption: Single Effect	800	0.03	17	40	428	0.03	16	38	377	0.03	16	38
	Engine Driven	900	0.0	10	65	855	0.02	10	62	855	0.02	10	62
100-200	Reciprocating: Water Cooled	540	0.75	0	30	513	0.7	0	29	513	0.7	0	29
	Reciprocating: Air Cooled	575	1.2	0	40	546	1.14	0	38	546	1.14	0	38
	Centrifugal	600	0.7	0	30	570	0.67	0	29	570	0.67	0	29
	Screw	725	0.7	0	30	689	0.67	0	29	689	0.67	0	29
	Absorption: Single-Effect	600	0.03	17	30	410	0.0	16	29	361	0.0	16	29
	Engine Driven	840	0.0	10	55	798	0.02	10	52	798	0.02	10	52
200-500	Reciprocating: Air Cooled	525	1.1	0	30	499	1.0	0	29	499	1.0	0	29
	Centrifugal	550	0.7	0	25	523	0.62	0	24	523	0.62	0	24
	Screw	600	0.7	0	25	570	0.7	0	24	570	0.7	0	24
	Absorption: Single-Effect	500	0.0	17	25	374	0.02	16	24	329	0.02	16	24
	Engine Driven	750	0.01	9	47	713	0.01	9	45	713	0.01	9	45
500-1000	Centrifugal	400	0.6	0	15	380	0.57	0	14	380	0.57	0	14
	Screw	525	0.65	0	15	499	0.6	0	14	499	0.6	0	14
	Absorption: Single-Effect	325	0.0	17	15	309	0.01	16	14	270	0.01	16	14
	Engine Driven	625	0.01	8	35	594	0.01	7	33	594	0.01	7	33
1000-2000	Centrifugal	350	0.6	0	15	333	0.57	0	14	333	0.57	0	14
	Absorption: Single-Effect	300	0.01	17	14	285	0.0	16	13	250	0.0	16	13
	Engine Driven	525	0.0	8	27	499	0.01	7	26	499	0.01	7	26

Note: Data derived from manufacturer-provided data from 1999-2000, and is validated by comparison with published data in journals, technical papers, and other sources including R. S. Means. Future cost data has been developed by reducing installed cost and efficiency by 5 percent (consistent with the cost reduction shown for CHP units), and future w/package cost reduction assumes 50 reduction in installation cost (not shown here) of chiller (installation cost of CHP unit remains unchanged).

2. **Building characteristics** are assigned based on census division data from DOE's 1995 Commercial Building Energy Consumption Survey (CBECS). Load profiles are taken from Lawrence Berkeley National Laboratory data on electric and thermal usage, by building type and climate region, developed by application of the DOE-2 model for commercial buildings.

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 1999) of the 57 largest electric utilities (in terms of GWh sales to commercial customers) representing over two-thirds of deliveries to the commercial 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 commercial 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 Commercial Buildings

1. Alabama Power Co
2. Appalachian Power Co
3. Arizona Public Service Co
4. Baltimore Gas & Electric Co
5. Boston Edison Co
6. Carolina Power & Light Co
7. Central Power & Light Co
8. Cincinnati Gas & Elec Co
9. Cleveland Electric Illum Co
10. Columbus Southern Pwr Co
11. Commonwealth Edison Co
12. Connecticut Light & Pwr Co
13. Consolidated Edison NY
14. Consumers Energy Co
15. Detroit Edison Co
16. Duke Energy Corp
17. Duquesne Light Co
18. Entergy Arkansas Inc
19. Entergy Gulf States Inc
20. Entergy Louisiana Inc
21. Florida Power & Light Co
22. Florida Power Corp
23. Georgia Power Co
24. Houston Lighting & Pwr Co
25. Idaho Power Co
26. Indiana Michigan Power Co
27. Jersey Central Pwr&Light
28. Kansas City Pwr & Light Co
29. Long Island Pwr Authority
30. Los Angeles City of
31. Massachusetts Electric Co
32. Memphis City of
33. Niagara Mohawk Pwr Corp
34. Northern States Power Co
35. Ohio Edison Co
36. Ohio Power Co
37. Oklahoma Gas & Elec Co
38. Pacific Gas & Electric Co
39. PacifiCorp
40. PECO Energy Co
41. Portland General Elec Co
42. Potomac Electric Power Co
43. PP&L Inc
44. PSI Energy Inc
45. Pub Svc Co of Colorado
46. Pub Svc Co of Oklahoma
47. Pub Svc Electric & Gas Co
48. Puget Sound Energy Inc
49. Salt River Proj Ag I & P Dist
50. San Diego Gas & Elec Co
51. South Carolina Elec&Gas
52. Southern California Edison
53. Tampa Electric Co
54. Texas Utilities Electric Co
55. Union Electric Co
56. Virginia Electric & Pwr Co
57. Wisconsin Electric Pwr Co

Initial Grouping of Sites

The model run begins with a database of potential customer sites (both commercial buildings and industrial facilities), that are organized by utility service area, building type, and size. Sites are organized as follows:

- Utility/Region and Building Type – Number of buildings and square footage by region are taken from EIA's 1995 Commercial Building Energy Consumption Survey. These buildings are then allocated into states using the Department of Commerce County Business Patterns (CBP) data, which indicates where all commercial businesses are located and number of employees. From this data, the sites are assigned to a utility based on their county (see Table A-2 for a list of utilities that are included) using a Contractor database. For those outside of these utility areas, sites are assigned to one of the nine census regions.

- Fuel Availability and Heating System – Based on its location and the natural gas costs database, the model determines whether natural gas is available to the site. Only buildings with natural gas availability were considered. Furthermore,

commercial buildings were divided into groups of buildings with different distribution systems, such as those that used boilers for space heating and those that use forced air heating (based on information from the CBECS).

- Facility Size – Based on the number of employees, a commercial facility peak demand is estimated using data on kW per employee (from CBECS data for each building type and region).

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 building type in a particular utility. To do so, the cash flows from gas and electric purchases over a 10-year period is calculated for each situation. From that, the simple payback is calculated from either generating with CHP or purchasing electricity to meet consumption needs is estimated for each combination of utility, building type, 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 for a particular utility, sector and size combination.

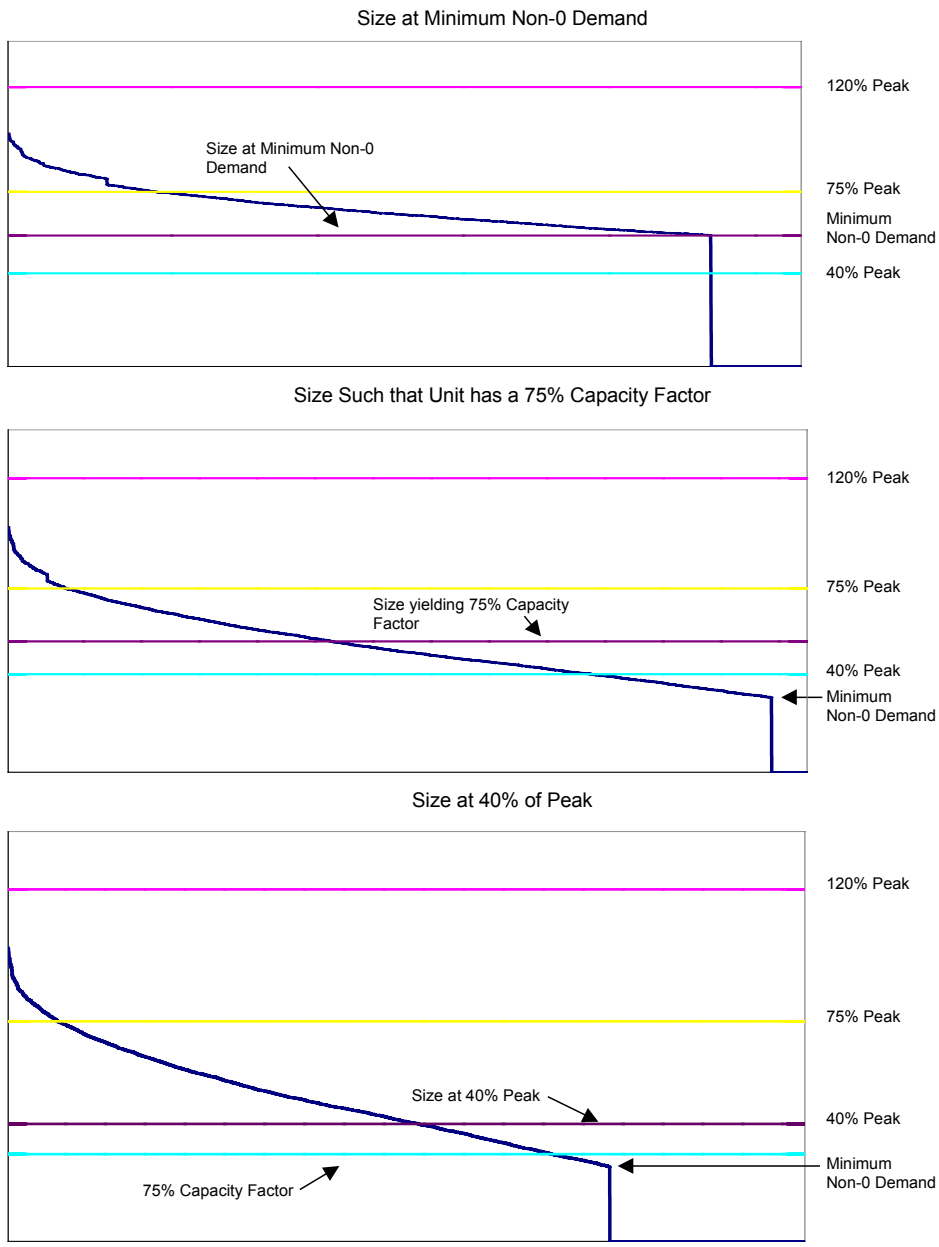
The model analyzes up to 32 different equipment, sizing, and operating scenario options for each site in addition to operating the existing equipment and purchasing electricity from the grid. This large number of scenarios is indicative of the fact that different options are best for different sites depending on many factors, most importantly site load profile and utility rate schedule. The list of options analyzed is contained in Table A-5 and A-6.

Equipment options analyzed include thermal storage, engine driven chillers, desiccant systems, CHP only systems and CHP with absorption chillers, and district energy systems (both CHP only and CHP with absorption) for multiple buildings. Analysis for multi-building facilities included a comparison of a central system versus systems in individual buildings within the facility. Depending on existing distribution systems of the facility, a district energy system was assigned costs for new heating and/or cooling distribution systems if necessary. A central system is selected only if it beats conventional options and other options at the individual building level.

CHP units are sized at the average site non-AC electric load in order to allow for adequate size and load factor for as many buildings as possible. This sizing practice has been adopted from industrial sector strategies, but tests in the building sector indicated that sizing at peak demand results in uneconomic load factors for most sites and sizing at minimum greatly reduces the number of buildings of adequate size for a CHP system.

Thermal storage systems, and electric, engine-driven and absorption chillers are sized to meet base load, peaking loads, or total cooling requirements depending on the scenario. Any unit sized to meet peaking or total requirements is oversized such that total system capacity was 120% of the peak load. Baseload sizing is set at the minimum (non-0) peak during the operating period for the unit as long as the minimum peak size was between 40% and 75% of maximum. If the size is outside the desired range, the size which would yield a capacity factor of 75% during operating periods is determined. This size would be used if it falls between 40% and 75% of peak. If it is outside the range, a size of 40% or 75% of peak is used. These sizing scenarios are illustrated in Figure A-2.

Figure A-2 Baseload Sizing Scenarios



Once equipment types and sizes are specified, operation is determined. Operational parameters include which technology is baseloaded and which units operate during on-peak and off-peak periods. Depending a site conditions and electric rate schedule it may make sense to operate absorption or engine driven chillers only during high-priced on-peak periods. Alternatively, it may be more economic to operate those chillers during all periods if off-peak charges are high or if all-period operation allows for a smaller electric chiller to be sized.

Thus, first, the results provide an estimate of how often a given CHP/cooling option is most economic or when it is best to purchase power from the grid instead of generating it with CHP. Second, the results provide a payback estimate of the dollar value of such generation. Because the results are produced at a very disaggregated level, they can be summarized by region, by unit size, by DG technology, by utility, or by industrial or commercial sector. Result summaries are provided in Section 3.

Table A-5 Scenarios Analyzed only for Single Buildings

Description		Base Case	Thermal Energy Storage Only		Engine Driven Chiller				CHP w / Desiccant	
		Electric Only	Electric Only w/TES	Electric Only w/TES	Engine Driven Chiller	Engine Driven Chiller	Engine Driven Chiller w/TES	Engine Driven Chiller	CHP (Engine) w/ Desiccant	CHP (Turbine) w/ Desiccant
On-Peak Operation	Baseload	Electric	Storage	Storage	Eng. Driven	Eng. Driven	Eng. Driven	Eng. Driven	Elec/Desc.	Elec/Desc.
	Peaking	Electric	Electric	Storage	Electric	Electric	Storage	Eng. Driven	Elec/Desc.	Elec/Desc.
Off-Peak Operation	Baseload	Electric	Electric	Electric	Electric	Eng. Driven	Electric	Eng. Driven	Elec/Desc.	Elec/Desc.
	Peaking	Electric	Electric	Electric	Electric	Electric	Electric	Eng. Driven	Elec/Desc.	Elec/Desc.
Sizing		Electric sized to maximum peak	Storage sized for baseload electric operation	Storage sized to maximum peak	Eng. Drv. Chill. Sized to minimum* peak during on-peak hours			Eng. Drv. Chill. sized to maximum peak	Desiccant sized to minimum* peak during on-peak hours	

*Minimum (non-0) peak during the operating period for the unit was used unless the minimum was less than 40% of maximum, in which case a unit sized between 40% and 75% of peak was used depending on load characteristics

Table A-6 Scenarios Analyzed for Both Single Buildings and Multiple Buildings (District Energy)

Description		CHP w/ Absorption										CHP Only	
		CHP (Engine) w/ absorption	CHP (Engine) w/ absorption	CHP (Turbine) w/ absorption	CHP (Turbine) w/ absorption	CHP w/ Absorption and TES (Engine)	CHP w/ Absorption and TES (Engine)	CHP (Engine) w/ absorption	CHP (Engine) w/ absorption	CHP (Turbine) w/ absorption	CHP (Turbine) w/ absorption	CHP (Engine)	CHP (Turbine
On-Peak Operation	Baseload	Absorption	Absorption	Absorption	Absorption	Absorption	Absorption	Absorption	Absorption	Absorption	Absorption	Electric	Electric
	Peaking	Electric	Electric	Electric	Electric	Storage	Storage	Absorption	Absorption	Absorption	Absorption	Electric	Electric
Off-Peak Operation	Baseload	Electric	Absorption	Electric	Absorption	Electric	Electric	Electric	Absorption	Electric	Absorption	Electric	Electric
	Peaking	Electric	Electric	Electric	Electric	Electric	Electric	Electric	Absorption	Electric	Absorption	Electric	Electric
Sizing		Absorber sized to minimum* peak during on-peak hours				Absorber sized to minimum* peak during on-peak hours, storage sized to meet remaining peak		Absorber sized to maximum peak				CHP Sized to Average Non-Ac Load	

*Minimum (non-0) peak during the operating period for the unit was used unless the minimum was less than 40% of maximum, in which case a unit sized between 40% and 75% of peak was used depending on load characteristics

Sensitivity Analyses

A number of scenarios were constructed to evaluate how sensitive the base case is to varying inputs. In doing so, there was a focus on how improving the cost and/or the efficiency of CHP impacts the market size. In addition, three sensitivities were added to illustrate the effects of changing energy prices on the CHP market for buildings.

As shown in Table A-7, 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+), and documented in Tables A-1 and A-2.

Table A-7. 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 involved changing energy prices. As shown in Figure A-2, natural gas prices increased dramatically in late 2000 and through 2001, which were not reflected in the base case gas prices. As a result, 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 call for wholesale natural gas prices to hover around $5/MMBTU for 2001-2002, 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 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 is 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.

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

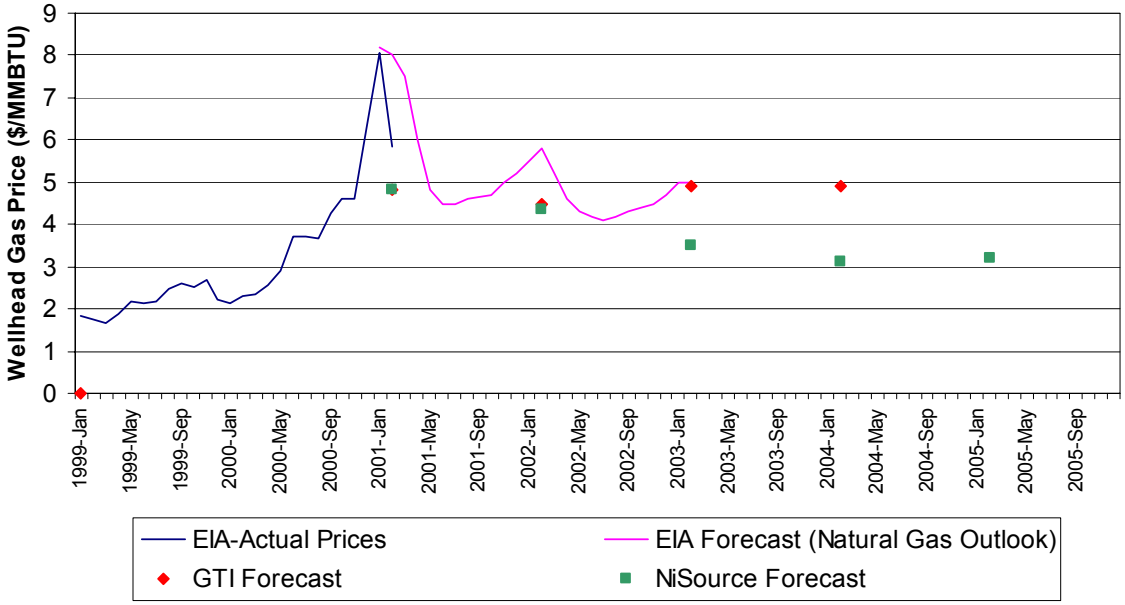
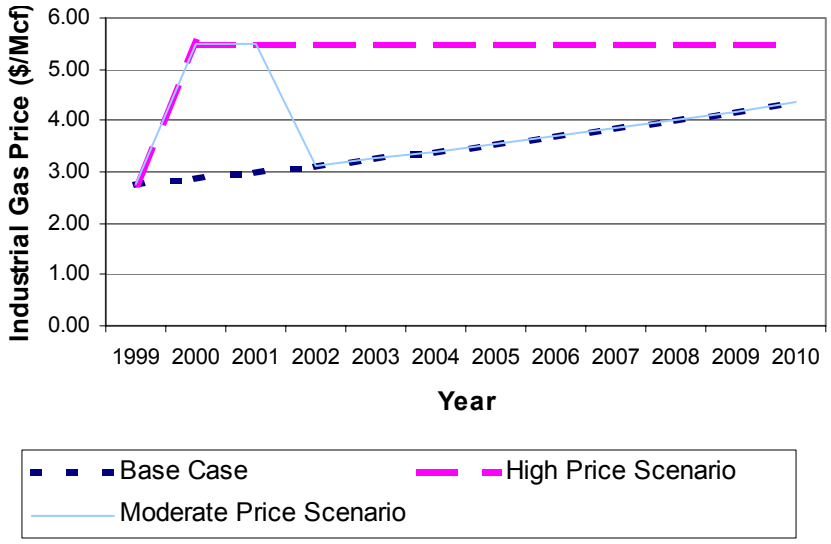


Figure A-4. Natural Gas Price Sensitivities Relative to Base Case (Industrial Gas Prices for Pacific Region only)



Since it is generally accepted that there is convergence in gas and electric prices, translating the effect of high natural gas prices on commercial building 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 that cost 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-8, 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 were coupled 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 buildings 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 be likely 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.

Table A-8. 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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