COMBINED HEAT AND POWER: CAPTURING WASTED ENERGY

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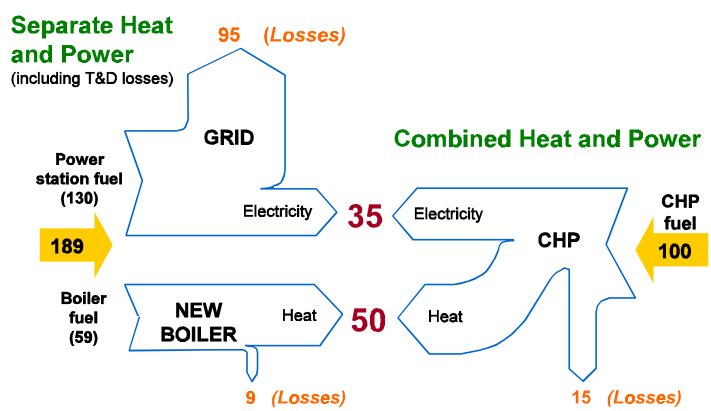
EXECUTIVE SUMMARY

Combined heat and power (CHP) systems (also known as cogeneration) generate electricity (and/or mechanical energy) and thermal energy in a single, integrated system (see Figure ES-1). This contrasts with common practice in this country where electricity is generated at a central power plant, and on-site heating and cooling equipment is used to meet non-electric energy requirements. The thermal energy recovered in a CHP system can be used for heating or cooling in industry or buildings. Because CHP captures the heat that would be otherwise be rejected in traditional separate generation of electric or mechanical energy, the total efficiency of these integrated systems is much greater than from separate systems.

Figure ES-1. Energy Flows in a Typical CHP System. Source: Kaarsberg and Elliott (1998).

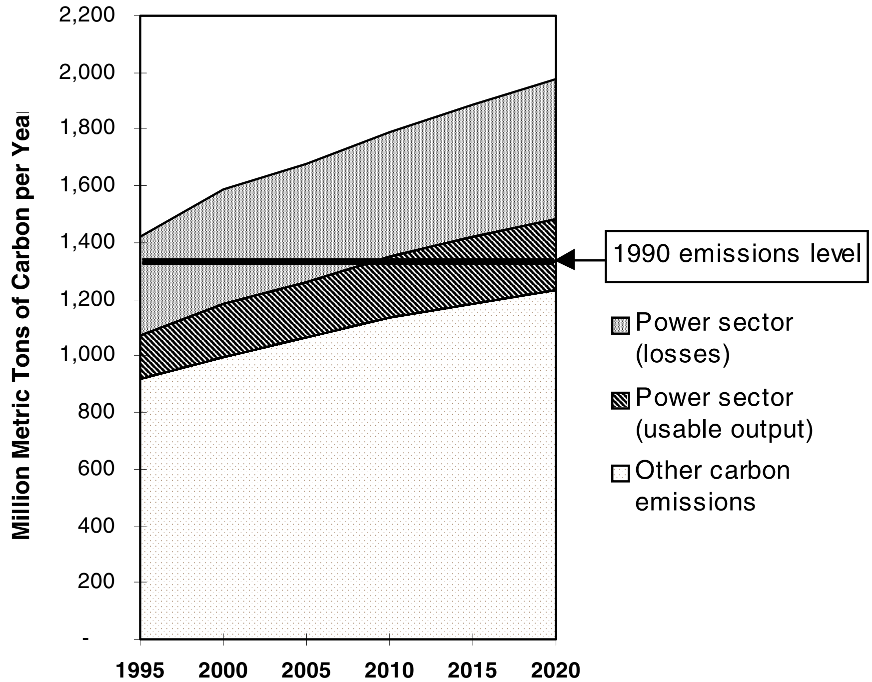


CHP is not a specific technology but rather an application of technologies to meet end-user needs for heating and/or cooling energy, and mechanical and/or electrical power. Recent technology developments have "enabled" new CHP system configurations that make a wider range of applications cost-effective. New generations of turbines, fuel cells, and reciprocating engines are the result of intensive, collaborative research, development, and demonstration by government and industry. Advanced materials and computer-aided design techniques have dramatically increased equipment efficiency and reliability while reducing costs and emissions of pollutants.

Conventional electricity generation is inherently inefficient, converting only about a third of a fuel's potential energy into usable energy. The significant increase in efficiency with CHP results in lower fuel consumption and reduced emissions compared with separate generation of heat and power. CHP is an economically productive approach to reducing air pollutants through pollution prevention, whereas traditional pollution control achieved solely through flue gas treatment provides no profitable output and actually reduces efficiency and useful energy output.

Energy losses in power generation represent a huge and growing source of carbon emissions during a period in which the United States will be seeking to reduce total emissions to below 1990 levels (see Figure ES-2).

Figure ES-2. Carbon Emission Projections. Source: EIA (1998).



Since there are two or more usable energy outputs from a CHP system, defining overall system efficiency is more complex than with simple systems. The system can be viewed as two subsystems, the power system (which is usually an engine or turbine) and the heat recovery system (which is usually some type of boiler). The efficiency of the overall system results from an interaction between the individual efficiencies of the power and heat recovery systems.

The most efficient CHP systems (exceeding 80 percent overall efficiency) are those that satisfy a large thermal demand while producing relatively less power. As the required temperature of the recovered energy increases, the ratio of power to heat output will decrease. The decreased output of electricity is important to the economics of CHP because moving excess electricity to market is technically easier than is the case with excess thermal energy. However, there currently are barriers to distributing excess power to market.

CHP can boost U.S. competitiveness by increasing the efficiency and productivity of our use of fuels, capital, and human resources. Dollars saved on energy are available to spend on other goods and services, promoting economic growth. Past research by ACEEE (Laitner et al. 1995) has shown that savings are retained in the local economy and generate greater economic benefit than the dollars spent on energy. Recovery and productive use of waste heat from power generation is a critical first step in a productivity-oriented environmental strategy.

History

CHP is a well-established concept with a long history. Engineers have always appreciated the tremendous efficiency opportunity of combining electricity generation with thermal loads in buildings and factories. Interest in CHP has fluctuated over the years because of changes in the marketplace and government policies, and the future is uncertain if we stay with current policies. CHP has evolved differently in Europe than in the United States.

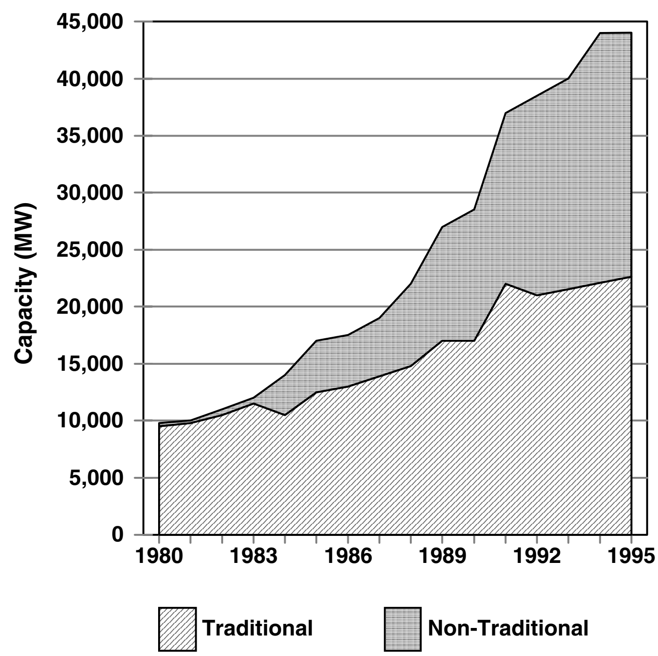
At the turn of the century in the United States, CHP systems were the most common electricity generators. As the cost and reliability of a separate electric power industry improved in the United States, users abandoned their on-site electric generation in favor of more convenient purchased electricity. By 1978, CHP's share of electricity use had fallen to only 4 percent (Casten 1998). In the late 1970s, after the energy price increases resulting from the 1973 and 1979 "energy crises," a renewed interest in CHP developed. U.S. industries found they could reduce energy demand if they built larger, more economical cogeneration plants optimized for both thermal and electric output (Cicio 1998). However, by this time, utilities had become sophisticated in protecting their markets for electricity. Many utilities refused to purchase excess power from CHP facilities, limiting on-site electricity generation to the level usable at the site (EEA 1998).

This situation motivated the enactment of the Public Utilities Regulatory Policy Act of 1978 (PURPA). This act played a critical role in expanding cogeneration into the marketplace by addressing many barriers that were present in the early 1980s.

Since PURPA provided the only way for non-utility generators to sell excess electricity, many independent power producers found a use for some of their waste thermal energy. This allowed them to qualify as a cogenerator under PURPA. These electricity-optimized CHP systems are called "non-traditional" cogenerators.

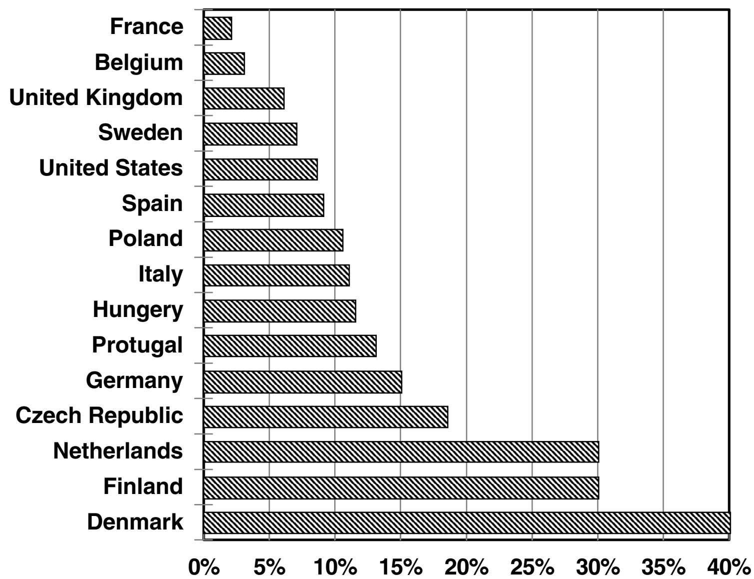
The 1980s saw a rapid growth of CHP capacity in the United States. Installed capacity increased from less than 10 gigawatts electric (GW_{e}) in 1980 to almost 44 GW_e by 1993 (see Figure ES-3). Most of this capacity was installed at large industrial facilities such as pulp and paper, petroleum, and petrochemical plants. These plants provided a "thermal host" for the electric generator.

Figure ES-3. Historical U.S. Industrial CHP Capacity. Source: EEA (1998)**.**



While on average the European Union countries obtain about the same amount of their electricity from CHP as the United States (9 percent), the market interest in CHP has gained in strength in many European countries. The United Kingdom has seen CHP's share of electricity power production double in the last decade. Installed CHP capacity has risen to 3.7 GW_e in 1997, with projections of increases to 5 GW_e by the year 2000. Similarly, Denmark and the Netherlands have seen tremendous growth in CHP since 1980, with these countries now obtaining more than 30 percent of their electricity from CHP. Figure ES-4 shows the percentage of national power production generated by CHP systems in 1997 in a variety of European countries, along with the United States (Brown 1998; Green 1999).

Figure ES-4. Share of National Electricity Produced in 1997 by CHP in Selected European Countries and the United States. Sources: EIA (1998); Green (1999)**.**



Markets

The authors have chosen to divide the market for CHP into three categories: industrial plants, district energy systems, and small-scale commercial and residential building systems.

The industrial sector represents the largest share of the current installed capacity in the United States and is the segment with the greatest potential for near-term growth. Large industrial CHP systems are typically found in the petroleum refining, petrochemical, or pulp and paper industries. These systems have an installed electricity capacity of greater than 50 Megawatts electric (MW_e) (often hundreds of MW_e) and steam generation rates measured in hundreds-of-thousands of pounds of steam per hour. Some facilities of this type are merchant power plants using combined cycle configurations. They are generally owned by an independent power producer that seeks an industrial customer for the steam and sells the electricity on the wholesale market. Sometimes the thermal customer may also contract for part of the electric power.

District energy systems (DES) are a growing market for CHP. DES distribute steam, hot water, and/or chilled water from a central plant to individual buildings through a network of pipes. DES provide space heating, air conditioning, domestic hot water, and/or industrial process energy. DES represent an important CHP market because these systems significantly expand the amount of thermal loads potentially served by CHP. In addition, DES aggregate thermal loads, enabling more cost-effective CHP. District energy systems may be installed at large, multi-building institutional campuses such as university, hospital, or government complexes or as merchant thermal systems providing heating (and often cooling) to multiple buildings in urban areas. The addition of CHP to existing district energy systems represents an important area for adding new electricity generation capacity (Spurr 1999).

With the arrival of low-cost, high-efficiency reciprocating engines, and the prospect of cost-effective, micro-combustion turbines, CHP is now becoming potentially feasible for smaller commercial buildings. This area, sometimes called “self-powered” buildings, involves the installation of a system that generates part of the electricity requirement for the building, while providing heating and/or cooling. Packaged systems, such as the reciprocating engines from Waukesha and Caterpillar, have a capacity beginning at 25 kilowatts electric (kW_e). This size range makes it possible to install CHP in smaller commercial applications, like fast-food restaurants, as well as larger commercial buildings.

The CHP supply market is beginning to develop. Besides these above end-use markets, four major categories of players are emerging:

- Project developers
- Equipment manufacturers
- Engineering and construction firms
- Energy supply companies

These groups offer a range of alternatives from design/build to build/own/operate to comprehensive energy supply/services.

Barriers

Although technologies used in CHP systems have improved in recent years, significant hurdles exist that limit widespread uses of CHP. Importantly, these hurdles have the effect of tending to "lock in" continued use of polluting and less-efficient electricity generation equipment. The main hurdles to CHP are:

- A site-by-site environmental permitting system that is complex, costly, time consuming, and uncertain.
- Current regulations do not recognize the overall energy efficiency of CHP or credit the emissions avoided from displaced grid electricity generation.
- Many utilities currently charge discriminatory backup rates and require prohibitive interconnection arrangements. Increasingly, utilities are charging (or are proposing to charge) prohibitive “exit fees” as part of utility restructuring to customers who build CHP facilities.

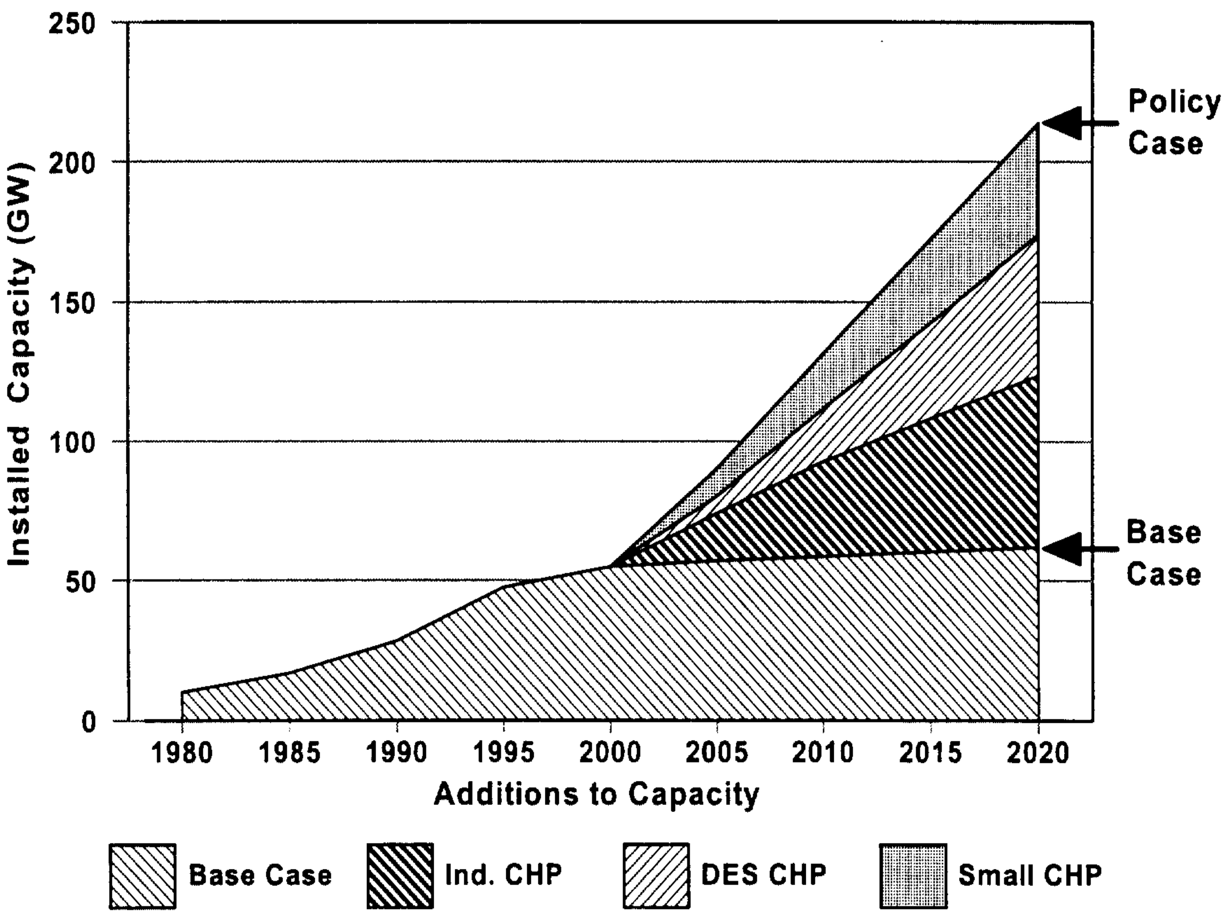
- Depreciation schedules for CHP investments vary depending on system ownership and may not reflect the true economic lives of the equipment.
- The market is unaware of technology developments that have expanded the potential for CHP.

In addition, development of new district energy systems as part of a CHP implementation face some additional barriers.

Potential

Current projections foresee a stagnation of the CHP market, with no significant additions to capacity because of the barriers discussed above (see Figure ES-5). However, if these barriers are removed, new capacity would likely be built. Estimating this added CHP capacity is difficult because of the diversity of system types and potential sites. However, it is anticipated that much of the early

Figure ES-5. Projected Additions to Installed CHP Capacity under the Base Case and Policy Cases (see main report for source information).



capacity will occur at larger industrial and institutional facilities that already have boiler systems and thermal distribution infrastructures (e.g., district energy systems). As time progresses, smaller industrial, institutional, and commercial facilities will begin to make up a greater part of the new capacity. New district energy systems, which aggregate the thermal demands of several facilities or buildings, will take longer to become a major factor in CHP because of the time required to develop and grow the piping network. Figure ES-5 presents the results of the analysis conducted for this report of the potential for CHP capacity with barriers removed. This analysis draws upon several other studies and analyses. Table ES-1 summarizes the impacts of this added capacity.

Table ES-1 Impact of Additional CHP Capacity

	New Additional CHP (GW_e)	Displaced Util. Gen. (TWh_e)	Cumulative Additional Capital ($Mill)	Net Energy Savings (TBtu)	Net Savings ($mill.)	Carbon (MMT_{CE})
Industrial (ACEEE)						
2010	34	217	22,100	1,214	5,918	34
2020	62	396	40,300	1,995	8,825	57
DES (Spurr 1999)						
2010	19	148	13,860	700	2,290	21
2020	50	390	19,540	1,600	5,210	51
Small CHP (Kaarsberg et al. 1998)						
2010	20	NA	NA	480	NA	17
2020	40	NA	NA	960	NA	35
Total						
2010	73	365	35,960	2,394	8,208	73
2020	152	786	59,840	4,555	14,035	143

NA — not reported in source

Policies

The U.S. Department of Energy and U.S. Environmental Protection Agency have committed to double CHP capacity by 2010. This represents a commitment to add approximately 50 GW_e of additional capacity. From the analysis conducted for this report, this goal appears realistic. Now that this ambitious goal for expanding CHP capacity has been set, the challenge is to take steps to convert this goal into action and reality with policies and programs.

Among the options that should be considered are:

- Reform of environmental permitting regulations and the permitting process to provide credit for the inherent efficiency of CHP systems.

- Reform electric utility regulations to provide fair and open access to the grid for procurement of standby power and excess generation sales.
- Modernize the depreciation schedules for CHP equipment to reflect current markets and technologies.
- Provide financing opportunities and incentives, such as tax credit, to spur interest in CHP systems.
- Develop educational and technical assistance programs to increase awareness of CHP opportunities and technologies.
- Initiate research and development activities to expand the range of CHP technologies, especially for small-scale systems.
- Installation of CHP systems in government facilities to demonstrate the benefits and provide market leadership.

Conclusions

Combined heat and power can contribute to the transformation of the United States' energy future. CHP offers significant, economy-wide energy efficiency improvement and emissions reductions. Our existing system of centralized electricity generation charts an unsustainable energy path, with increasing fuel consumption and carbon emissions, while continuing to squander over two-thirds of the energy contained in the fuel. At least half this wasted energy could be recaptured if we shift from centralized generation to distributed systems that cogenerate power and thermal energy. Besides saving energy and reducing emissions, distributed generation also addresses emerging congestion problems within the electricity transmission and distribution grid.

CHP represents an opportunity to make significant progress toward meeting our Kyoto commitments on greenhouse gas reductions. The local air quality improvements and opportunities for economic growth presented by CHP are equally compelling. CHP presents an opportunity to improve the "bottom line" for businesses and public organizations, while also providing a path for improving the environment.

During the last two years, CHP has become an important element of the national energy debate. The United States has taken the first steps toward setting in place policies to promote CHP by establishing a national target. The DOE and the EPA have begun to review the means for achieving this target. The target now needs to be translated into concrete policies and programs at both the federal and state levels for overcoming the significant hurdles to greater use of CHP.

The private sector also needs to take a leadership role. The primary barriers to greater CHP use are regulatory and institutional, not technical or economic. The private sector must work with government regulators and policy makers to insure that competition and incentives for innovation are preserved, while creating a favorable regulatory environment for CHP. And the private sector should actively pursue adoption of CHP — both for environmental and "bottom-line" benefits.

I. INTRODUCTION

Combined heat and power systems (also known as cogeneration) generate electricity (and/or mechanical energy) and thermal energy in a single, integrated system. This contrasts with common practice in this country where electricity is generated at a central power plant, and on-site heating and cooling equipment is used to meet non-electric energy requirements. The thermal energy recovered in a CHP system can be used for heating or cooling in industry or buildings. Because CHP captures the heat that would be otherwise be rejected in traditional separate generation of electric or mechanical energy, the total efficiency of these integrated systems is much greater than from separate systems.

As the United States moved toward the December 1997 Kyoto meeting of the United Nations' Framework Convention on Climate Change (FCCC), efficiency advocates in government, industry, and the public interest sector were seeking technology responses to climate change that could provide significant reductions of domestic greenhouse gas (GHG) emissions. Three studies, two prepared by non-profit research groups (Alliance et al. 1997; Bernow 1997) and the third, prepared by five national laboratories for the U.S. Department of Energy (Interlaboratory Working Group 1997), identified CHP as one of the most important technology responses to climate change, with the potential to provide almost 10 percent of GHG emission reductions in the United States required under the Kyoto agreements.

These studies, together with activities by CHP market leaders, captured the attention of the Clinton Administration. In his October 22, 1997 climate change speech at the National Geographic Society in Washington, D.C., the President said:

> *"We must unleash competition in the electricity sector to remove outdated regulations and save Americans billions of dollars. We must do it in a way that leads to even greater progress in cleaning our air and delivers a significant down payment in reducing greenhouse gas emissions. Today, two-thirds of the energy used to provide electricity is squandered in waste heat. We can do much, much better."*

As President Clinton acknowledged, conventional electricity generation is inherently inefficient, converting only about a third of a fuel's potential energy into usable energy. However, CHP is not just a climate change strategy. Because of its inherent efficiency, CHP represents an economically attractive strategy to address energy supply requirements in many sectors of the economy, while helping to address local and regional air quality concerns.

CHP Goal

Momentum has built in both the government and private sector for CHP. This momentum was evidenced by the DOE's commitment at the first CHP Summit[2] to double CHP capacity by 2010. This commitment to add approximately 50 gigawatts electric[3] of additional capacity was seconded by the U.S. Environmental Protection Agency two days later. The CHP goal established by the DOE and the EPA is based on studies, such as one prepared by ACEEE (Geller et al. 1998) showing that a doubling of CHP capacity is technically and economically feasible (see Section VI). Now that this ambitious goal for expanding CHP capacity has been set, the challenge is to take steps to convert this goal into action and reality.

At the CHP Summit, Daniel Reicher, DOE's Assistant Secretary for Energy Efficiency and Renewable Energy, called for a more comprehensive assessment of the potential for CHP and the policies needed to achieve the federal government's goal. This report attempts to address these requests, and will:

- identify the benefits of CHP,
- provide a brief history of CHP,
- survey CHP technologies,
- review current U.S. CHP markets,
- estimate the future potential for U.S. CHP,
- identify market barriers to the deployment of the CHP, and
- suggest policy strategies that can be used to accelerate implementation of CHP.

How CHP Helps the Environment and the Economy

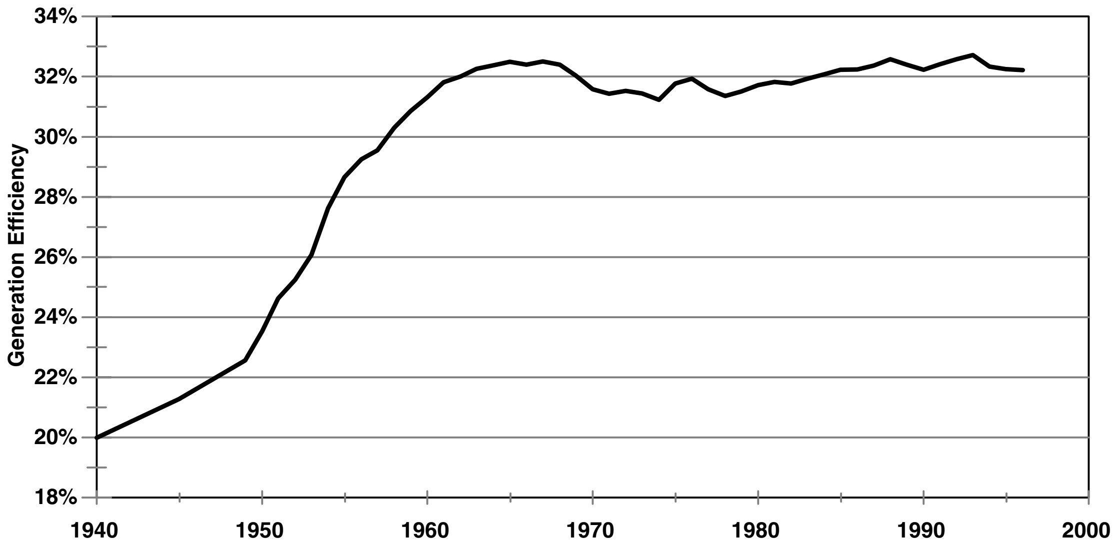
CHP is much more energy efficient than separate generation of electricity and thermal energy because heat that is normally wasted in conventional power generation is recovered as useful energy. (See Section III.) The average efficiency of U.S. electric generation has been stagnant since the 1960s at about 32 percent (see Figure 1), while overall efficiencies of greater than 80 percent are currently being achieved today by CHP systems (Casten 1998).

The significant increase in efficiency with CHP results in lower fuel consumption and reduced emissions compared with separate generation of heat and power. Emission reductions include GHG and regulated air pollutants such as nitrogen oxides (NO_x), sulfur dioxide (SO_2), and particulates. Compared with NO_x emission rates of 0.5 pounds (lbs) per megawatt-hour electric (MWh_e) for conventional generation, CHP typically emits less than 0.1 lbs/MWh_e (Bluestein 1998). Similar

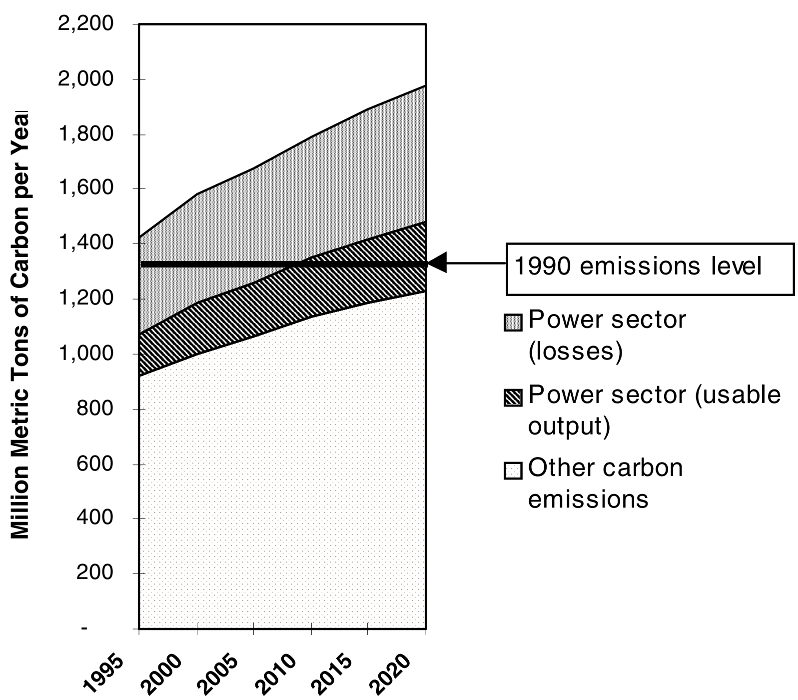
[2] Sponsored by the DOE on December 1, 1998, in Arlington, Virginia.

[3] A gigawatt is 1,000 megawatts electric or 1 million kilowatts electric.

Figure 1. Efficiency of Electricity Generation in the United States. Source: Trigen Energy Corp., derived from EIA data (Hall 1998).



reduced emission levels are achieved for other pollutants. CHP is an economically productive approach to reducing air pollutants through pollution prevention, whereas traditional pollution control achieved solely through flue gas treatment provides no profitable output and actually reduces efficiency and useful energy output. In addition, since CHP generally displaces older thermal and electric generating equipment with newer, cleaner, and more efficient equipment, air pollution and GHG emissions are further reduced.



Energy losses in power generation represent a huge and growing source of carbon emissions, during a period in which the United States will be seeking to reduce total emissions to below 1990 levels (see Figure 2).

Of the total 1997 U.S. carbon emissions of 1,480 million metric tons of carbon equivalent (MMT_{CE}), power generation was responsible for 532 MMT_{CE} or 36 percent (EIA 1998). In addition, this market sector was responsible for 5.9 million tons of NO_x (27 percent of total NO_x emissions) and 12.8 SO_2 (85 percent of total SO_2 emissions) (Alliance et al. 1997). The efficiency of this carbon-intensive sector is low; only 32 percent of the fuel is converted into useful energy. Efficiency in the power sector is projected to increase only marginally (to 34 percent by the year 2020) while power generation carbon emissions are projected to increase 213 MMT_{CE} to a total of 745 MMT_{CE} (EIA 1998).

CHP can boost U.S. competitiveness by increasing the efficiency and productivity of our use of fuels, capital, and human resources. Dollars saved on energy are available to spend on other goods and services, promoting economic growth. Past research by ACEEE (Laitner et al. 1995) has shown that savings are retained in the local economy and generate greater economic benefit than dollars spent on energy. Recovery and productive use of waste heat from power generation is a critical first step in a productivity-oriented environmental strategy.

On a more local basis, CHP can be an engine for economic development, offering clean, low-cost energy solutions to many sectors of the economy. Some regions of the country are facing constraints in their electricity supply infrastructure, as evidenced by power shortages during the summer of 1998. New generation capacity will be needed to meet growing demand for electricity and replace aging power plants as they are retired. The market is already beginning to respond by building new "merchant" power plants in regions with limited reserves.

Our current electricity supply infrastructure relies upon power plants located remotely from the centers of electricity load growth. It is becoming more difficult and costly to site new supply infrastructure due to congestion and opposition from neighbors to transmission and distribution (T&D) lines and substations. Many people consider these facilities unsightly and potentially dangerous. The process to gain approval for the construction of these facilities can take years. In some areas, the T&D system is becoming overtaxed, leading to increased concerns about the reliability of electricity service, particularly during periods of peak demand. CHP alleviates this problem by locating the generation near the demand. In addition, district cooling systems have the ability to shift power demand from on-peak to off-peak periods using thermal energy storage.

By generating power at or near the site ("distributed generation") and using thermal energy storage, CHP helps avoid the construction of new central station power plants, and capacity in existing facilities can be freed for use by other customers for whom CHP is not an option. CHP capacity can be constructed more quickly than large central facilities, and the thermal energy can be recovered to meet local demand. In addition, distributed generation reduces the load on the T&D infrastructure, helping to address capacity constraints and reliability concerns. Distributed generation reduces the need to build new T&D facilities, while allowing for demand growth. The load on the existing infrastructure is reduced by adding capacity within a transmission constrained area, freeing capacity to meet other users' demand. In addition, some electric loads can be converted to thermal or direct drive systems, further decreasing the electricity load.

In addition, co-location of electric generation and use can result in significant energy savings because it reduces losses from the power flowing through wires and transformers. Currently about 9 percent of electricity generated in the United States is lost in the T&D system (EIA 1997a).

Conventional separate heat and power generation wastes enormous quantities of energy, with significant environmental and economic implications. CHP represents a low-risk strategy for reducing pollution and increasing economic efficiency. CHP technologies are proven, cost-effective, and readily available. What are needed are policy and market signals that encourage adoption of CHP.

II. History and Status of CHP

CHP is a well-established concept with a long history. Engineers have always appreciated the tremendous efficiency opportunity of combining electricity generation with thermal loads in buildings and factories, converting 80 percent or more of the fuel into usable energy. Interest in CHP has fluctuated over the years because of changes in the marketplace and government policies. Because of current policies and attitudes, the future for CHP is uncertain if we stay on the current course. CHP has evolved differently in Europe than in the United States.

United States

At the turn of the century, CHP systems were the most common electricity generators. Because larger systems were more cost-effective, manufacturing facilities were among the first sites for CHP systems. In addition, in the late 19th century, district heating systems were common in urban areas, supplying many buildings. Many were municipally owned and these aggregated loads provided attractive sites to generate electricity to meet an emerging demand for electricity. In 1900, industrial and district energy CHP facilities generated about a quarter of U.S. electricity production.

As the cost and reliability of a separate electric power industry improved in the United States, users abandoned their on-site electric generation in favor of more convenient purchased electricity. By 1978, CHP's share of electricity use had fallen to only 4 percent (Casten 1998). However, some industries, such as pulp and paper and petroleum refining, have continued to operate their CHP facilities. These industries have high steam loads creating attractive economics for CHP. In addition, these industries generate "free" byproduct fuels, such as wood waste or low quality refiner gas. The industry must dispose of these wastes, and by using these fuels the cost of both disposal and external fuel purchase can be avoided. At these "traditional" CHP facilities, the designers sized the electrical generation capacity to match the on-site thermal requirements.

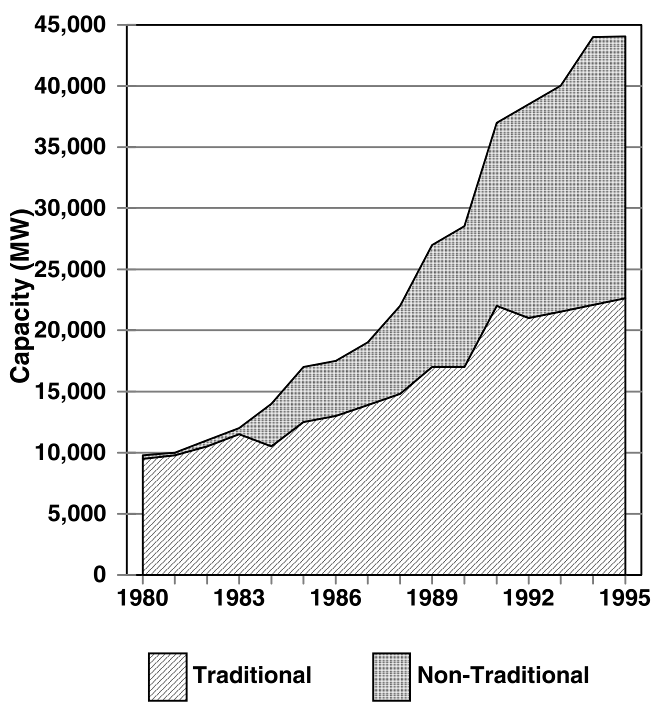
In the late 1970s, after the energy price increases resulting from the 1973 and 1979 "energy crises," a renewed interest in CHP developed. U.S. industries could reduce industrial energy demand if they built larger, more economical cogeneration plants optimized for both thermal and electric output (Cicio 1998). By this time, utilities had become sophisticated in protecting their markets for electricity. Many utilities refused to purchase excess power from CHP facilities, limiting on-site electricity generation to the level usable at the site (EEA 1998).

The Dow Chemical Company, at the encouragement of the Governor of Michigan, met with the Carter White House to propose that the law be changed to allow highly efficient industrial cogeneration plants to sell excess power to the utility at the utilities' "avoided cost." In response, the Carter Administration drafted legislation that became the Public Utilities Regulatory Policy Act of 1978, which included measures to promote cogeneration (Cicio 1998).

PURPA played a critical role in expanding cogeneration into the marketplace by addressing many barriers that were present in the early 1980s. These barriers included high standby charges from utilities and unwillingness to buy excess power. PURPA limited the standby charges and required utilities to interconnect with these facilities and purchase power at the utility's avoided cost (EEA 1998).

Since PURPA provided the only way for non-utility generators to sell excess electricity, many independent power producers found a use for some of their waste thermal energy. This allowed them to qualify as a cogenerator under PURPA. The 1980s saw a rapid growth of CHP capacity in the United States. Installed capacity increased from less than 10 GW_e in 1980 to almost 44 GW_e by 1993 (see Figure 3). Most of this capacity was installed at large industrial facilities such as pulp and paper, petroleum, and petrochemical plants. These plants provided a "thermal host" for the electric generator.

Figure 3. Historical U.S. Industrial CHP Capacity. Source: EEA (1998)**.**



Many of these facilities were installed with the primary intent of generating electricity and are referred to as non-traditional cogenerators.

Because PURPA allowed systems using as little as 5 percent useful thermal energy to qualify, many systems were optimized for electricity production rather than overall efficiency. A myth exists about "PURPA Machines," in which a trivial use was found for the steam solely to qualify under the Act. Only a few documented cases of these facilities exist. These facilities represent a small fraction of the capacity installed during the period (EEA 1998).

The passage of the Energy Policy Act of 1992 (EPAct) resulted in changes in the power market, creating a new category of independent power producers (IPP) that did not need to find a use for waste heat. This change is reflected in the rapid decline in the rate of CHP additions after 1993 (see Figure 3). The barriers that PURPA was intended to address changed with the market and a new set of barriers to efficient cogeneration emerged. Avoided costs were falling rapidly, driven by declining fuel cost and changes in generation mix. Rather than buying power at their avoided cost, utilities were purchasing power in wholesale markets based on market conditions.

Concurrently, many utilities increased standby charges to cogenerators in part to discourage cogeneration and the resulting loss of sales revenue. Also, many utilities, in response to a proposal for a cogeneration facility in their service territory, would discount their power rates to the industrial facility in order to render the cogeneration proposal uneconomic. These developments increased the attractiveness of generating power for wholesale markets and removed much of the incentive for IPPs to seek steam customers to make cogeneration viable. These developments taken together slowed, but hardly eliminated, expansion of cogeneration capacity during the 1990s (EEA 1998).

The Energy Information Administration (EIA) reports that in 1997 CHP accounted for about 52 GW_e of electricity generation capacity (7 percent of total U.S. capacity) and about 328 Terawatt-hours (TWh_e) or 9 percent of production (EIA 1998). Two-thirds of the electricity generated by CHP was produced from natural gas, with coal and renewables each accounting for about 14 percent.

Since the early 1990s, about 3 GW_e of new cogeneration generation capacity has been added annually in the United States (Table 1). These capacity additions have come from an average of 70 new facilities per year, with an average capacity of 42 MW_e per facility. The number of new projects declined from a high of 81 in 1994 to 46 in 1996 (Poirier 1997). Preliminary data suggest a further decline in 1997 for both total added capacity and number of projects (Carroll 1998; Schwinn 1999; Williams 1998). While interest in new systems has remained strong among end-users, industry experts attribute the decline in new installations to uncertainty associated with utility restructuring, siting constraints, increasing difficulties in obtaining emissions permits for new facilities (especially in EPA non-attainment areas), and increased costs and difficulties in dealing with local utilities. The high fees that some utilities are charging customers that begin generating electricity on-site (to recover so called "stranded" investments) is a very serious economic constraint (Carroll 1998; Davidson 1998).

EIA, the Gas Research Institute, and Hagler Bailly Consulting, Inc. project only modest growth in CHP capacity for the coming decade under existing policies. Much of the new capacity is projected

Table 1. Additions to Cogeneration Electricity Generation Capacity

	Number	Capacity (MW_e)	Avg. Capacity (MW_e)
1991 & Before	1,684	33,332	20
1992	70	3,039	43
1993	81	2,377	29
1994	77	4,874	63
1995	73	1,844	25
1996	47	2,397	51
Avg. Annual	70	2,906	42

Source: Hagler Bailly (1996).

to be installed by IPPs. These experts indicate that the shift to non-CHP merchant power plants will continue and that low energy prices and the costs of overcoming barriers make CHP less attractive to IPP project developers who will likely be responsible for most of the new capacity added (EEA 1998; EIA 1998; Schwinn 1999).

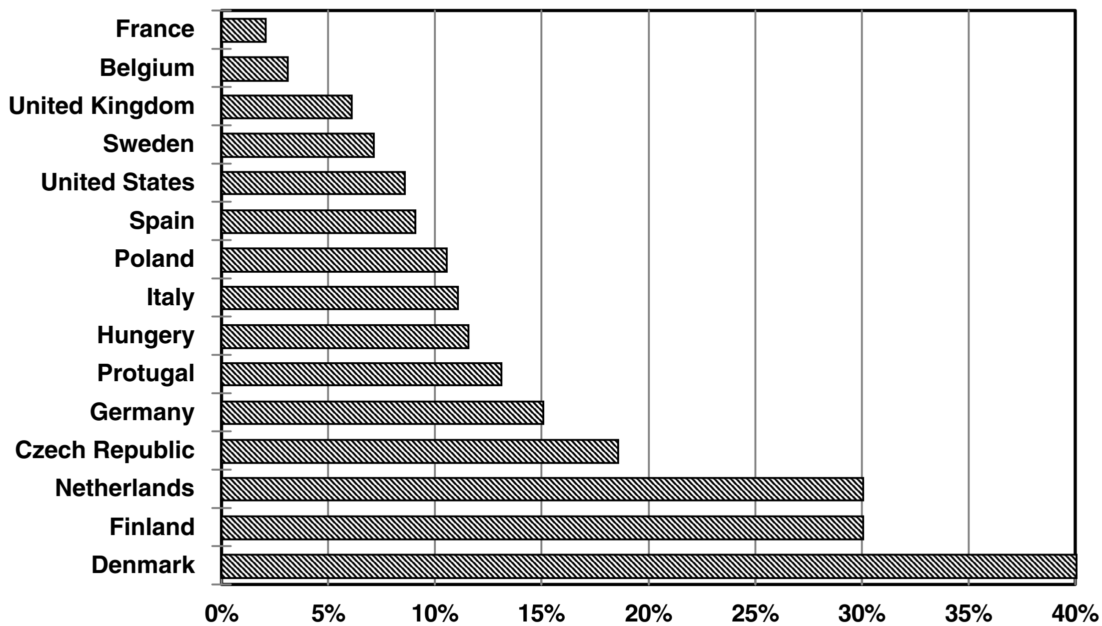
Europe

On average, the European Union countries obtain about 9 percent of their electricity from CHP, about the same as the United States. However, in contrast to the United States, where recent additions to capacity have declined, the market interest in CHP has gained in strength in many European countries. The United Kingdom has seen CHP's share of electricity power production double in the last decade. Installed CHP capacity has risen to 3.7 GW_e in 1997, with projections of increases to 5 GW_e by 2000. Similarly, Denmark and the Netherlands have seen tremendous growth in CHP since 1980, with these countries now obtaining more than 30 percent of their electricity from CHP. Figure 4 shows the percentage of national power production generated by CHP systems in 1997 in a variety of European countries, along with the United States (Brown 1998; Green 1999).

In the 1980, CHP systems in Europe faced many of the same barriers currently faced in the United States (Brown 1998; Green 1999). A number of factors have contributed to policies that have removed these barriers and promoted growth in CHP. Privatization of the electricity marketplace (referred to in Europe as liberalization), concerns about global climate change, and increased availability of natural gas have been the most important (Green 1999).

The motivation for European countries to promote CHP has varied from country to country. In Denmark, CHP was seen as a "green" strategy, with government policies mandating the installation

Figure 4. Share of National Electricity Produced in 1997 by CHP in Selected European Countries and the United States. Sources: EIA (1998); Green (1999).



of CHP, in some cases at costs that would not be considered economic in other countries with a less committed environmental agenda. In the Netherlands, efficiency inherent with CHP was viewed as an answer to national security concerns about reliance on imported natural gas. In some Eastern European countries, such as Poland, CHP is seen as a path to modernize their energy infrastructures to allow for economic growth. Many countries have also come to appreciate CHP's contribution to local air quality. Many in the environmental community in the European Union (EU) came to CHP as the third element in a comprehensive energy and environment strategy, along with end-use efficiency and renewables (Brown 1998).

The policies that have resulted in increased CHP implementation have also varied by country. The most common and important have been the opening of electricity markets to non-utility generators. Many nations had national electric utility companies that have now been broken up, as is happening in the United States. This opening of markets, combined with cheap natural gas from the North Sea and Eastern Europe, has resulted in the emergence of combined-cycle gas turbine (CCGT) independent power plants, as is also being seen in the United States. While advocates of these IPPs have claimed efficiencies of greater than 55 percent, the reality has shown efficiencies of only slightly greater than 45 percent. The economic and environmental costs of wasting this energy have concerned policy makers in a number of countries, leading to a moratorium on construction of new

CCGT plants in countries such as the United Kingdom and the Netherlands, unless they cogenerate (Green 1999).

The presence of a well-developed district energy infrastructure has made extensive implementation of CHP possible in countries such as Denmark, Finland, the Czech Republic, Hungry, and Poland. These district energy systems provided ready, aggregated thermal loads for CHP systems. In Denmark, the development of district energy systems has been established as a national policy imperative, leading to the highest share of electricity coming from CHP of any country. Danish systems frequently link residential, commercial, and industrial users in large systems, allowing for a more constant thermal load than is achievable with smaller, less diverse systems (Brown 1998; Spurr 1999).

The setting of national targets or goals has been an important policy driver in many of these countries. As concerns about climate change increased in Europe, CHP was identified as a key element in the climate change strategy for several countries, including the United Kingdom, Denmark, Sweden, the Netherlands, Finland, and Germany. These countries established goals or targets for CHP, which has motivated changes in other policies. In 1997 the European Commission proposed a strategy, in the context of the European Union energy policy, for facilitating the development of CHP and removing barriers to its market penetration. The plan calls for doubling the current 9 percent CHP penetration in the European Union by 2010, providing an estimated reduction in carbon dioxide ($CO_{2)}$ emissions of 150 MMT_{CE} per year or approximately 4 percent of the total European Union CO_2 emissions in 2010. Governments are reviewing their policies and regulations to encourage CHP. Current implementation trends indicate that these goals are likely to be achieved before the target date (Brown 1998).

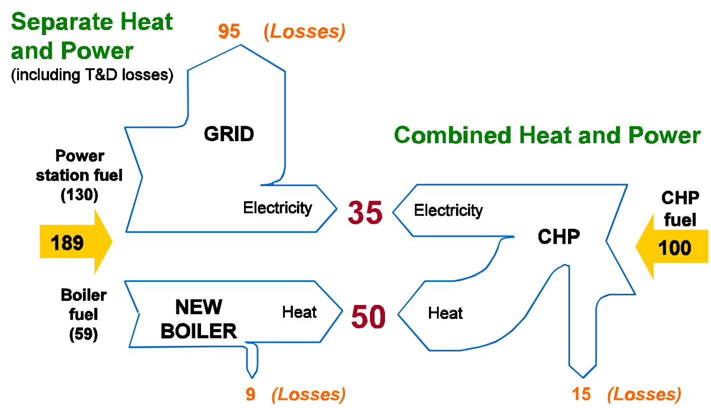
An important element influencing the course of CHP policy has been the emergence of strong advocates for CHP. This increased interest in CHP evolved from groups that advocated for expanded district or community energy systems. These advocates came to the view that for new systems to be economic, they needed to cogenerate. With discussion of electricity marketplace liberalization beginning in the 1980s in the United Kingdom, the Combined Heat and Power Association (CHPA) emerged as an important voice advocating for the creation of an open electricity system. The CHPA felt that if CHP were given a fair chance in an open marketplace, it would succeed as the lowest-cost energy option. By the mid-1990s, CHP systems had become established as important players in the electricity market in the United Kingdom. By this time the utility liberalization movement was expanding to other European countries, with CHP organizations emerging in many countries. Cogen Europe was organized to coordinate these national level activities, be an advocate in Brussels for EU policies favorable to CHP, and serve a coordinating role between national efforts (Brown 1998; Green 1999).

III. CHP TECHNOLOGIES

CHP is not a specific technology but rather an application of technologies to meet end-user needs for heating and/or cooling energy, and mechanical and/or electrical power. Recent technology developments have "enabled" new CHP system configurations that make a wider range of applications cost-effective. New generations of turbines, fuel cells, and reciprocating engines are the result of intensive, collaborative research, development, and demonstration by government and industry. Advanced materials and computer-aided design techniques have dramatically increased equipment efficiency and reliability while reducing costs and emissions of pollutants.

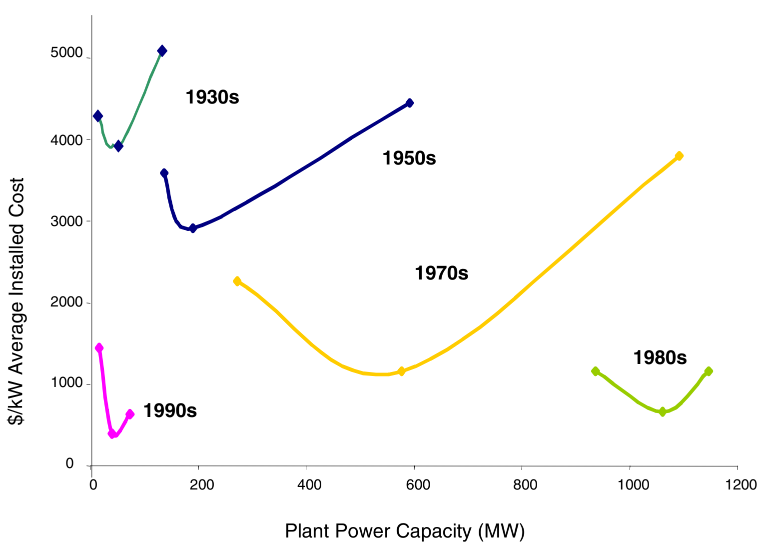
Figure 5 illustrates the efficiency benefits of a typical CHP system compared to separate generation of heat and power. The total efficiency of the CHP approach is 85 percent, almost double the 45 percent total efficiency of separate heat and power.

Figure 5. Energy Flows in a Typical CHP System. Source: Kaarsberg and Elliott (1998).



This section provides an overview of power generation technologies, describes CHP system configurations and related technologies, summarizes the current mix of CHP technologies, and discusses energy efficiency in the context of CHP.

Figure 6. Optimal Power Plant Size. Source: Bayless (1994).



Steam turbines, gas turbines, combined cycles, and reciprocating engines are the major current technologies used for power generation and CHP, as discussed below. Technology evolution has changed the optimal size of power generation facilities. From the 1930s until the 1980s, the lowest cost per MW_e shifted to larger and larger steam turbine generation facilities. However, developments between 1980 and 1990 reversed this trend, with the most cost-effective plants shifting from steam turbines of about 1,000 MW_e to gas turbines of less than 50 MW_e (see Figure 6) (Bayless 1994). These same recent advances in efficient, cost-effective power generation technologies, in particular advanced combustion turbines, have also allowed for a wider range of CHP system configurations. These technologies have expanded opportunities for CHP systems, and increased the fraction of electricity they can produce. Emerging technologies, such as fuel cells, Stirling engines, and micro-turbines, are likely to reduce the optimum size of power plants further and continue to expand the CHP potential (Interlaboratory Working Group 1997).

Collaborative research by government and industry has contributed significantly to the new generations of turbines and engines (see "DOE Advanced Turbine System [ATS] Program" text box, below). This equipment uses advanced materials and computer-aided design techniques to increase equipment efficiency and reliability dramatically while reducing costs and emissions of pollutants. New small-scale gas turbines (below 500 kW_e) and reciprocating engines (down to 50 kW_e) will soon be available with improved performance and lower costs, with even smaller equipment on the horizon. This smaller equipment has the potential to further expand the number of sites where CHP can potentially be installed. In fact, a turbine or engine can replace existing fuel burners in many existing industrial boilers, adding electricity generation capability while reducing emissions of pollutants (Interlaboratory Working Group 1997).

The recent application of advanced materials and welding techniques has resulted in improvements to boiler tubing and heat exchangers, which increase efficiency and durability. In addition, the introduction of packaged, turnkey boilers offer modular expansion capability while reducing the level of operator expertise or attention associated with conventional pressure-vessel designs (Hart 1998).

Overview of Power Generation Technologies

Steam Turbines — Steam turbine plants are the most numerous type of power plant in the world today. Any type of fuel can be burned in a boiler to make steam, which drives a steam turbine that in turn spins a generator. As discussed below, in gas turbine combined cycle plants the hot gases exiting from the gas turbine are used to make steam, which drives a separate steam turbine that in turn spins a generator. Steam turbines can also be installed in place of pressure reducing in conventional, thermal-only steam systems to generate modest amounts of power at very low cost (Casten 1998)

In electric-only steam turbine plants, the steam exiting the turbine is condensed. This boosts the power output by creating a vacuum on the exit end of the steam cycle, thus making the steam turbine spin faster. However, most of the energy ends up in the condenser cooling system (using cooling towers that put the heat into the air, or dumping the heat into a body of water such as a river).

DOE Advanced Turbine System (ATS) Program:

The Advanced Turbine Systems Program has as its goal to develop and demonstrate ultrahigh- efficiency natural gas turbine systems. The program objectives include:

- Boost system efficiency to 60 percent or greater for utility combined cycle systems and achieve a 15 percent improvement in existing industrial systems.
- Reduce the cost of electricity produced by these systems by 10 percent compared to conventional systems.
- Offer expanded fuel flexibility.
- Lower NO_x emissions to less than 10 parts per million (ppm) with less than 25 ppm carbon monoxide without the use of post-combustion emissions controls.
- Offer reliability, availability, maintainability, and durability that equals or exceeds current turbine systems.

To date the program has:

- Developed a process to produce critical alloy materials with six times better properties at one-sixth the cost of current alloys.
- Tested ceramic blades for 1,000 hours and ceramic-composites for 5,000 hours. These materials offer durability and cost advantages over conventional metal blades.
- Achieved a world endurance record for a gas turbine operated at 2,600^o F.
- Demonstrated the feasibility and benefits of using Continuous Fiber Ceramic Composite material in a gas turbine combustor liner.

The first industrial ATS engine that incorporates these technologies, the Solar Turbines Mercury 50, is currently beginning to ship. This engine, which is more than 40 percent efficient, has achieved low emissions levels in field tests, with further NO_x reductions anticipated with the introduction of a catalytic combustor.

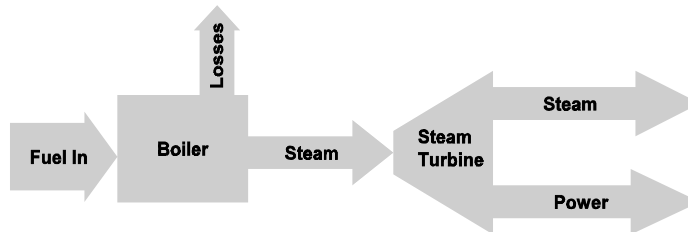
It is anticipated that ATS technology will play an important role in the future of CHP by improving cost-effectiveness and emissions signatures for turbine-based systems. The total cost of the program to the government has been $700 million, with a cost share of $450 million by industry.

Source: DOE (1999a).

In the traditional CHP configuration, called a "bottoming cycle," a boiler generates steam that enters a steam turbine (see Figure 7.) The heat that would otherwise be dissipated in the cooling towers of a conventional power plant is recovered, usually in the form of steam or pressurized hot water. This heat can be used for industrial processes or district heating systems, or can be converted to chilled water for district cooling or industrial processes using absorption chillers or steam turbine chillers. Steam can also be used to drive steam turbine-driven feed-water pumps in the boiler house since they can be very cost-effective and will continue to operate in the event of a power outage.

This CHP configuration is currently the dominant approach to CHP, accounting for more than 40 percent of the industrial electricity cogenerated (EIA 1997b). The electricity fraction of the usable energy output in these systems is constrained by physics to less than 25 percent of the total usable energy for building and industrial applications. The recent application of computerized design techniques and advanced materials, especially for turbine seals, has reduced costs and improved the reliability and efficiency of steam turbines (Hart 1998).

Figure 7. Typical Bottoming Cycle CHP System.



Combustion Turbines — Combustion turbines (see Figure 8) generate shaft power by compressing air that is fed into a combustor where it is mixed with fuel (usually natural gas or a distillate fuel). The hot gases from the combustor enter the turbine stage where they expand, turning the turbine shaft. The shaft drives both the compressor and the load, with the net available power being the difference. Combustion turbines can be used in a CHP "topping cycle" configuration (see Figure 9), in which fuel is combusted in an engine that generates power. The waste heat from the engine is recovered in a Heat Recovery Steam Generator (HRSG). Combustion turbine-based CHP systems account for about 6 percent of the sites and about 5 percent of the industrial electricity generated (EIA 1997b).

Figure 8. Combustion Turbine. Source: DOE (1999a).

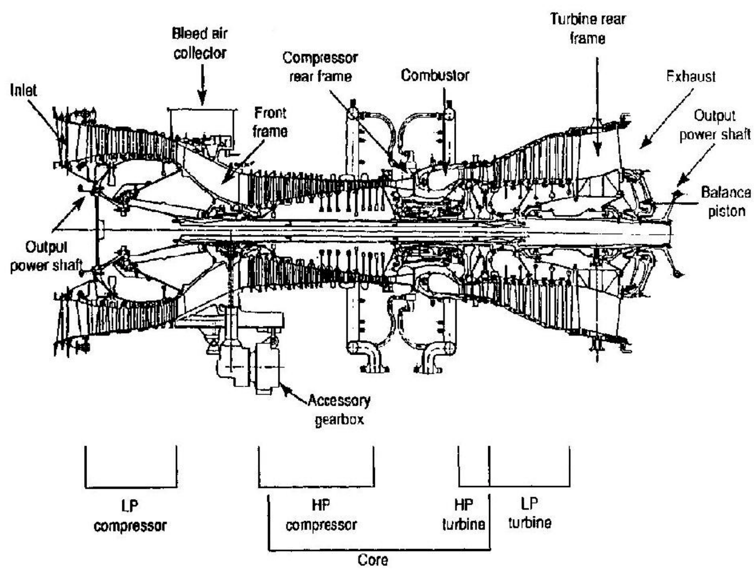
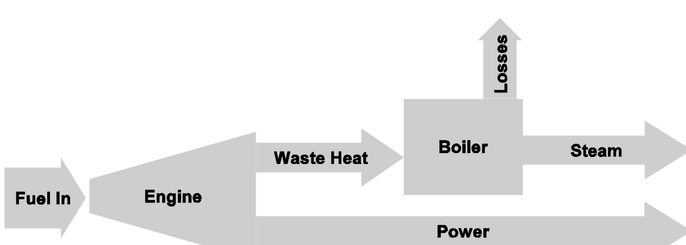


Figure 9. Typical Topping Cycle CHP System.

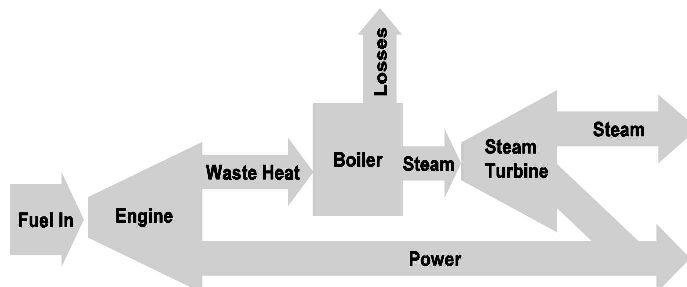


Design experience from jet engines and advanced materials have increased the efficiency and reliability of turbines, while reducing their cost and emissions (see above box on "DOE Advanced

Turbine System [ATS] Program"). Today's turbines are also available in a wider range of sizes, with current offerings now available below 500 kW_e (Parks 1998). With the introduction of new turbines, turbine-based systems are likely to represent a greater portion of future CHP systems (Carroll 1998; Davidson 1998; Parks 1998).

In the combined cycle (see Figure 10), the topping and bottoming cycles are combined with a steam turbine generating power from a portion of the steam produced by the boiler. This configuration allows for higher power to heat ratios than the other configuration.

Figure 10. Typical Combined Cycle CHP System.



Micro-turbines are small combustion turbines with a capacity of less than 250 kW_e. It is anticipated that they will enter the commercial market in the next few years. At least two manufacturers, Capstone Turbine Corporation and Allied Signal, Inc., are expected to begin selling micro-turbines in 1999, and about a dozen others including Ingersoll-Rand and Elliott Energy Systems are also developing products (Kaarsberg et al. 1998). The cost and performance of current micro-turbines are not yet attractive (Price 1998). In order to address these issues, the DOE is currently deciding whether to fund work to apply technologies developed in the ATS program to micro-turbines (Parks 1998). If current system costs can be reduced to the levels many anticipate, and efficiency and reliability can be improved, these products may be a major stimulus to the development of smaller CHP systems (Price 1998).

*Reciprocating Engine*s — Reciprocating engines (e.g., diesel engines) can also be used to generate electricity. These internal combustion engines convert fuel to shaft power, which then spins a generator. Diesel generators have long been used to generate small amounts of electricity at industrial, commercial, and institutional sites, either for continuous use or for backup in case of utility power failure. Recent developments in engine design have increased power efficiency (now approaching 50 percent) and reliability, while dramatically reducing the emissions of these engines. These new designs can use a variety of liquid and gas fuels, including natural gas. For emissions reasons, natural gas-fired engines have become dominant for continuous operation applications (i.e., not emergency generators) (Interlaboratory Working Group 1997).

The total efficiency achievable in reciprocating engine CHP depends on the temperature of the heat recovered. Heat can be recovered from the engine exhaust, cooling water, and oil, though the resulting temperature is fairly low (e.g., 250° F) — a typical peak temperature of a modern hot water district heating system. In Europe, engine-based district energy CHP systems often operate in excess of 80 percent efficiency.

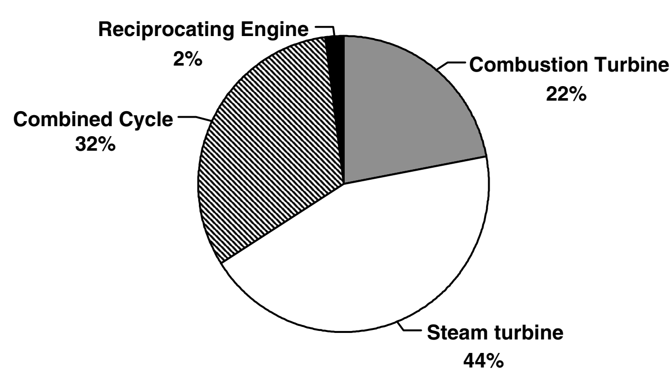
Reciprocating engines are the dominant independent generation technology for small installations, accounting for 47 percent of sites but only 2 percent of the power generation (Hagler Bailly 1996). In the industrial sector in 1995, reciprocating systems generated less than 1 percent of total cogenerated electricity but accounted for 5 percent of the installed systems with an average installed size of less than 1 MW_e. This type of system is most commonly found in the food products industry (SIC 20) (EIA 1997b).

Fuel Cells — As noted earlier, fuel cells are an emerging technology that converts chemical energy directly into electricity, producing very little pollution. While not engines in the strict sense that they do not produce shaft power, they can supply combined heat and power. Heat is a by-product of the reaction and can be recovered in much the same way as with turbines and reciprocating engines. Available databases do not list any installed fuel cell capacity but this technology will gain an increasing market share in coming years as new types of fuel cells (some which produce high temperature waste heat, such as solid-oxide and phosphoric-acid fuel cells) enter the marketplace (Interlaboratory Working Group 1997).

Other CHP Configurations — Some industrial processes, such as melting of metals and hydrocarbon cracking, generate high temperature exhaust streams. An HRSG can be used to capture some of this heat, replacing or supplementing a fuel-fired boiler. These systems are principally installed in pulp and paper, chemicals, and petroleum refining and account for about 4 percent of the electricity cogenerated by industry (EIA 1997b).

Market Share of Power Generation Technologies — Each of the technologies and configurations discussed is of different relative importance. Figure 11 shows each technology's capacity share of the industrial CHP market. This topic will be discussed later in greater depth.

Figure 11: Technology Share of Industrial CHP.
Source: EEA (1998).



Related Technologies

In addition to boiler and engine technologies, several other technologies can play an important role in CHP systems.

Absorption Refrigeration — Absorption chillers use heat, instead of mechanical energy, to provide refrigeration. In absorption cooling, the refrigerant is absorbed into an absorbent solution after it has been expanded, rather than compressed as in a mechanical system. The solution is then cooled. The heat then drives the refrigerant out of the solution under pressure, which is then expanded in an evaporator much as in a mechanical system. Water/lithium bromide and ammonia/water are the two most common refrigerant/absorbent pairs.

Two types of absorption chillers are commercially available: single- and double-effect systems. Triple-effect units are under development. In multi-effect systems, the heat from one stage is used to drive the next stage or "effect," thus increasing the efficiency. This can increase the coefficient of performance (COP) from less than 1 for a single-effect system to over 1.5 for a triple-effect unit. The complexity of multi-effect chillers increase their cost. Table 2 provides typical characteristics of different types of absorption chillers (Kaarsberg et al. 1998). Boilers and combustion turbines can generate steam or hot water of a temperature necessary to drive the most efficient types, double-and triple-effect chillers. Reciprocating engines and some fuel cells can be used to drive single-effect chillers (Kaarsberg et al. 1998).

Table 2. Characteristics of Four Different Absorption Chillers

Chiller Type	Thermal COP	Input Temperature Range (F)
Single-effect	0.7	212-250^0
Double-effect	1.1	300-340^0
Triple-effect	>1.6	340-400^0

Source: Kaarsberg et al. 1998.

Absorption chillers can be used to reshape the thermal and electric profile of a facility by shifting cooling from an electrical load to a thermal load. This shift can be very important for buildings where space conditioning loads vary with the season. Since cooling predominates during the warmer season and space heating is required during cooler seasons, a better year-round thermal load factor results, allowing for more electrical generation from a CHP system.

Thermal Energy Storage — Thermal energy storage systems (TES) level out or shift thermal loads by storing heat or cool. Many cool storage systems use a phase change medium, usually ice, in order to increase the density of the stored energy. TES systems have most commonly been used to shift electric cooling loads to off-peak periods of lower electricity pricing. Most systems operate on a daily cycle, though weekly and seasonal cycles have been used with success. While the TES system can be expensive, this cost can be offset somewhat if the capacity of the heating or cooling equipment can be reduced.

In a CHP system, TES provides the ability to decouple the thermal load from the power load. If the thermal load cycles, the TES can be designed to level out the load, allowing the power equipment to operate at a constant load. Alternatively, the TES can absorb thermal energy, allowing the power load to fluctuate in response to demand or pricing. This second scenario holds great promise as utility pricing is deregulated and the price of base-load electricity falls while peak electricity pricing increases, as has been seen in California and the Midwest.

Gasification and Biomass-Based Fuels — With the exception of boiler-based CHP systems, most CHP facilities require a liquid or gaseous fuel (e.g., a distillate fuel oil or natural gas). Since the power-to-heat ratio of boiler-based systems is limited, this limits the amount of power that can be generated in a CHP system if a solid fuel is used. This has led to renewed interest in gasification technologies to produce fuel for use in turbines. The solid fuels of greatest interest are biomass (e.g., waste from the wood products industry or urban waste wood) and coal. Recent developments have moved gasification of these two fuels closer to commercialization (Interlaboratory Working Group 1997).

For the wood products industries, biomass gasification is considered a critical technology for future competitiveness (AFPA 1994), in particular the gasification of black liquor from pulp mills. The thermal-to-electric ratio of pulp and paper production is shifting toward greater utilization of electricity. As will be discussed in the next section, the industry currently produces much of its own electricity from waste. As the electricity requirements continue to grow, there will be an increasing mis-match between thermal and electric demand. By moving to black liquor gasification and combined cycle technologies, the pulp and paper industry can increase the power to heat ratio of its power plants, allowing the industry to move from a net-electricity purchaser to a net-electricity producer (Nilsson et al. 1995).

Efficiency in the CHP Context

Since there are two or more usable energy outputs from a CHP system, defining overall system efficiency is more complex than with simple systems. The system can be viewed as two subsystems: the power system, which is usually an engine or turbine, and the heat recovery system, which is usually some type of boiler. The efficiency of the overall system results from an interaction between the individual efficiencies of the power and heat recovery systems.

The total overall system efficiency (η_{system}) of a CHP system is defined as:

$$\eta_{system} = \frac{e_{thermal} + e_{electric} + e_{mechanical}}{e_{fuel\ in}} \tag{1}$$

All the energy values (**e**) must be defined in the same units (e.g., British thermal units [Btu] or kWh_e).[4] For the example in Figure 5:

$$\eta_{system} = \frac{50 + 35}{100} = 85\%$$

The heat and power subsystems each have their own characteristic efficiencies:

$$\eta_{thermal} = \frac{e_{thermal}}{e_{fuel\ in}} \tag{2}$$

$$\eta_{power} = \frac{e_{electric} + e_{mechanical}}{e_{fuel\ in}} \tag{3}$$

Again for the example in Figure 5:

$$\eta_{thermal} = \frac{50}{100} = 50\%$$

$$\eta_{power} = \frac{35}{100} = 35\%$$

Since energy is used sequentially for multiple purposes, the CHP subsystem efficiencies will be different from comparable equipment used in separate heat and power. For example, the efficiencies of the separate power and thermal systems in Figure 5 are:

$$\eta_{separate\ thermal} = \frac{50}{59} = 85\%$$

$$\eta_{separate\ power} = \frac{35}{130} = 27\%$$

[4] One kWh_e equals 3,412 Btu.

The power-to-heat ratio (**α**) is the ratio of electrical and mechanical energy to thermal energy, and varies with equipment selection and system design. This ratio is expressed as:

$$\alpha = \frac{e_{electric} + e_{mechanical}}{e_{thermal}} \quad \textbf{(4)}$$

So, for the example in Figure 5:

$$\alpha = \frac{35}{50} = 0.7$$

In many CHP applications, the electricity generation equipment will be sized to match the base thermal load, and supplemental fuel will be fired in the boiler to satisfy swings in thermal demand. This assumption leads to a final system performance metric that is important in characterizing CHP systems. The *net power heat rate* ($h_{net\ power}$) is defined as:

$$h_{net\ power} = \frac{e_{fuel\ in\ system} - e_{fuel\ in\ separate\ heat}}{e_{electric\ system} + e_{mechanical\ system}} \quad \textbf{(6)}$$

Net thermal heat rate is analogous to the boiler heat rate in a conventional steam system. Since we assume that the thermal load would exist independent of the CHP facility, the net power heat rate represents the additional fuel input required to generate a unit of power produced by a CHP system, over and above that required to generate the thermal energy alone. The net power heat rate is analogous to the electric heat rate for separate power generation. For the example in Figure 5:

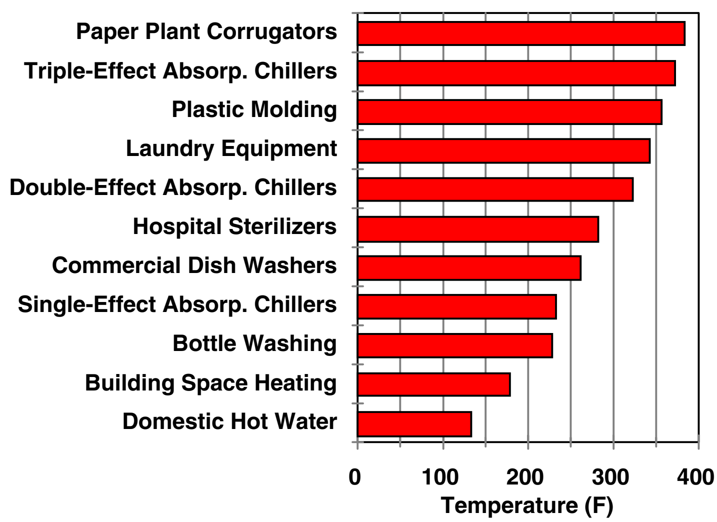
$$h_{net\ power} = \frac{100 - 59}{35} = 4{,}000$$

The net power heat rate for CHP systems is typically in the range of 4,000 to 4,600 Btu/kWh$_e$, which reflects a net power efficiency of between 70 to 85 percent. The low magnitude of these numbers is appreciated by comparison to stand-alone electric power generation, where heat rates frequently range from 7,000 for the newest systems to well over 10,000 Btu/kWh$_e$ for older systems.

The most efficient CHP systems (exceeding 80 percent overall efficiency) are those that satisfy a large thermal demand while producing relatively less power (i.e., **α** < 1). As the required temperature of the recovered energy increases, the power-to-heat ratio will decrease. The decreased output of electricity is important to the economics of CHP because it is technically easier to move excess electricity to market than is the case with excess thermal energy. However, as discussed below, there currently are barriers to distributing excess power to market.

What limits the overall efficiency of many CHP systems is the limited availability of thermal loads, particularly lower temperature thermal requirements that can be satisfied with CHP while maximizing power output. Unfortunately, most existing manufacturing plants are designed to operate on steam with pressures in the range of 50 to 150 pounds per square inch (psig), with temperatures in the range of 300 to 370ºF. This constrains the maximum efficiencies that can be achieved. Figure 12 shows examples of temperature requirements for a variety of industrial end-uses, and commercial building space heating and domestic hot water requirements. In many cases current district energy distribution systems make use of higher temperature steam or water than is required to satisfy the demand in order to minimize the initial capital cost of the distribution system and heat exchange equipment. If this equipment is optimized for the lower operating temperature, significantly greater system efficiencies can be achieved.

Figure 12. Temperature Requirements for Commercial Building and Industrial Processes. Source: IDHA (1983).



Some CHP systems can be configured to produce other forms of usable energy. Since about half the electricity in the United States is used by motors, there may be opportunities to use the shaft power directly, rather than incur the additional equipment investments and inefficiencies associated with converting shaft power to electricity and then back into shaft power in a motor. Many larger motor loads, such as fans, pumps, chillers, and air compressors, can be driven directly. Since these large motor loads account for a disproportionate share of motor energy, significant energy savings can be realized (XENERGY, Inc. 1998). The most common applications of direct drive are:

- the production of compressed air with an engine-driven compressor,
- the production of chilled water with an engine-driven chiller,
- operation of large fans in boiler houses using steam turbines, and
- operation of pumps at water and waste water plants with either an engine or steam turbine.

An even more innovative approach is the production of compressed air by bleeding high pressure air off the compressor stage of a combustion turbine.

IV. Markets for CHP

The CHP marketplace is evolving, driven by changes in the electric utility marketplace and in technology, as just discussed in Section III. The CHP market can be divided into three major categories: industrial systems, district energy systems, and building systems. Each of these categories can be further subdivided.

Industrial

The industrial sector represents the largest share of the current installed capacity in the United States and is the segment with the greatest potential for near-term growth. Large industrial CHP systems are typically found in the petroleum refining, petrochemical, or pulp and paper industries. These systems have an installed electricity capacity of greater than 50 MW_e (often hundreds of MW_e) and their steam generation rates are measured in hundreds-of-thousands of pounds of steam per hour. Some facilities of this type are merchant power plants using combined cycle configurations. They are generally owned by an independent power producer that seeks an industrial customer for the steam and sells the electricity on the wholesale market. Sometimes the thermal customer may also contract for part of the electric power.

The 1994 Manufacturing Energy Consumption Survey (MECS) breaks down manufacturing cogeneration by industry and technology configuration. About 1,300 manufacturing facilities cogenerated in 1994, with two-fifths reporting the use of boilers and steam turbines (see Table 3). Another fifth reported using a combination of generation technologies. Pulp and paper reported the largest number of sites (265), which account for a fifth of the industrial sector total. Food, lumber, and petroleum refining each account for about 16 percent of the sites.

Table 4 shows a breakdown of industrial cogeneration by industry (EIA 1997b). Much of the future additions to capacity are projected to be dominated by the same sectors (EEA 1998; ONSITE 1997a, 1997b; ONSITE Sycom 1998).

Thousands of boilers provide process steam to a broad range of smaller manufacturing plants. These boilers offer a large potential for adding new electricity generation capacity (from 50 kW_e to 50 MW_e) by either modifying boiler systems to add electricity generation (e.g., re-powering existing boilers with a combustion turbine), replacing the existing boiler with a new CHP system or installing back-pressure steam-turbine-generators. This represents an important growth segment for CHP generation capacity over the coming decade.

ONSITE Energy Corporation recently completed assessments of the remaining cost-effective potential for CHP in the chemical (1997a) and food (1997b) industry groups. These studies identified more than 36 GW_e of additional CHP capacity in these two industrial sectors alone. For the chemical industries, ONSITE estimates that more than 31 GW_e of additional on-site electricity generation potential remains, of which almost 16 GW_e represents potential for CHP. For the food industry, ONSITE estimates 34.5 GW_e of additional on-site generation potential, with the CHP potential at 20 GW_e.

As Figure 13a shows, the greatest potential for capacity additions comes from systems in the 40 to 150 MW_e range. However, as Figure 13b reveals, this represents a relatively small number of sites, with the greatest number of sites in the 1 to 10 MW_e size range (ONSITE 1997a, 1997b). Many industry experts feel that this situation is common to other industries as well.

Table 3. Industrial Cogeneration Sites in 1994

Number of Sites	Total	Boiler w/ Steam Turbine	CT w/ HR	Combined Cycle CT	Recip. w/ HR	Process HR	Combination of technologies	Other
All Industry	1306	490	81	8	69	64	243	351
Food (SIC 20)	217	93	27	4	41	4	15	33
Lumber (SIC 24)	192	95	0	0	NA	NA	9	88
P&P (SIC 26)	265	162	14	4	NA	15	38	32
Chem. (SIC 28)	208	63	26	0	NA	16	77	26
Petro. (SIC 29)	70	4	7	0	0	8	32	19
Metals (SIC 33)	48	20	3	0	0	NA	NA	25
Other	306	53	4	0	28	21	72	128

Source: EIA 1997b
Notes: NA – data not available
CT – Combustion Turbine
Recip. – Reciprocating engine
HR – heat recovery using a boiler
Other – technology not otherwise categorized (e.g., geothermal) or type not reported.

Table 4. Industrial Cogeneration Production (TWh_e) in 1994

	Total	Boiler w/ Steam turbine	CT w/ HR	Combined Cycle CT	Recip. w/ HR	Process HR	Combination of technologies	Other
All Industry	127.8	45.7	6.9	0.7	0.4	4.5	61.3	8.4
Food (SIC 20)	6.8	3.4	0.8	0.1	0.2	0.0	0.9	1.3
Lumber (SIC 24)	1.9	1.5	0.0	0.0	0.0	0.0	0.3	0.1
P&P (SIC 26)	50.9	30.9	2.2	0.6	NA	1.7	11.7	3.9
Chem. (SIC 28)	44.2	4.6	NA	0.0	NA	1.7	34.3	3.5
Petro. (SIC 29)	14.2	0.0	0.8	0.0	0.0	0.7	12.1	0.7
Metals (SIC 33)	5.6	3.7	NA	0.0	0.0	NA	NA	1.9
Other	4.1	1.5	3.1	0.0	0.2	0.4	2.1	-3.1

Source: EIA 1997b
Notes: NA – data not available
CT – Combustion Turbine
Recip. – Reciprocating engine
HR – heat recovery using a boiler
Other – technology not otherwise categorized (e.g., geothermal) or type not reported

Figure 13a. CHP Capacity Potential in the Chemical and Food Industries by Size of On-Site Capacity. Source: ONSITE (1997a, 1997b).

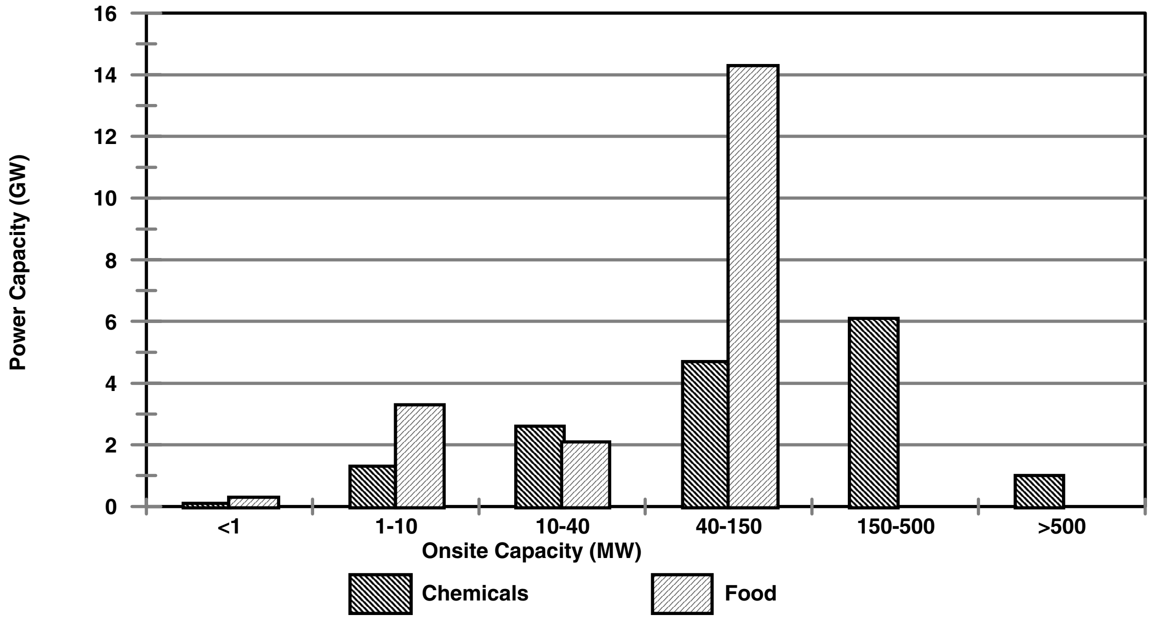
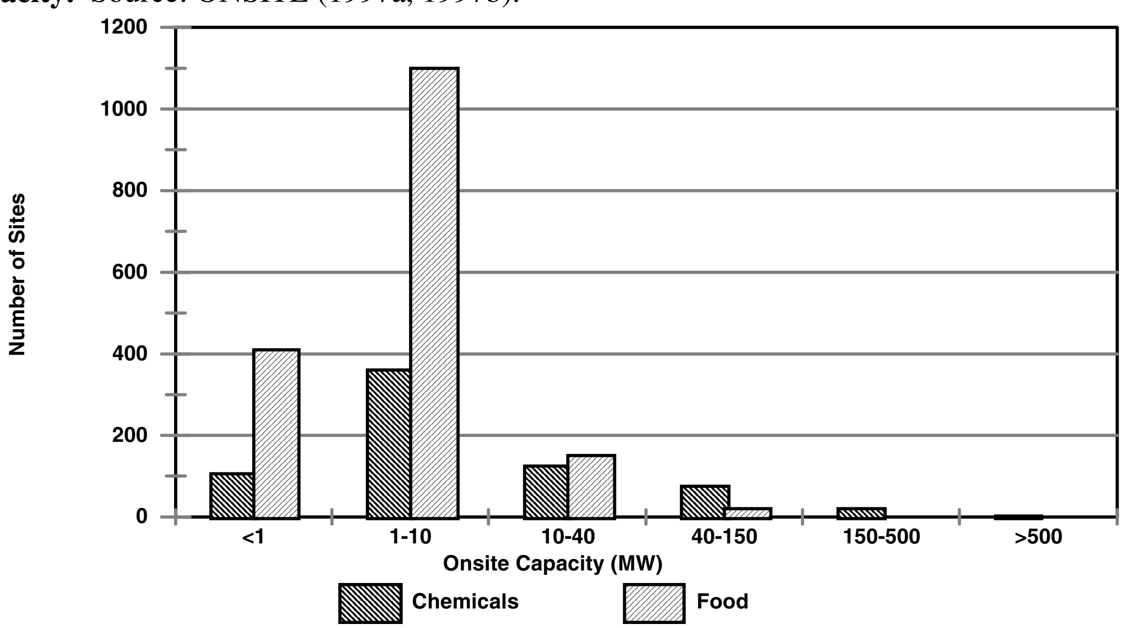


Figure 13b. CHP Site Potential in the Chemical and Food Industries by Size of On-Site Capacity. Source: ONSITE (1997a, 1997b).



Based on this information, it is reasonable to assume that the large systems (greater than 40 MW_e) will represent the capacity that is most likely to be first installed. This size system is already the dominant size (GRI 1998). The area for greatest growth in the midterm is the medium-sized system from 1 to 40 MW_e, with the smaller systems (less than 1 MW_e) awaiting the introduction of new, more cost-effective technologies.

District Energy Systems

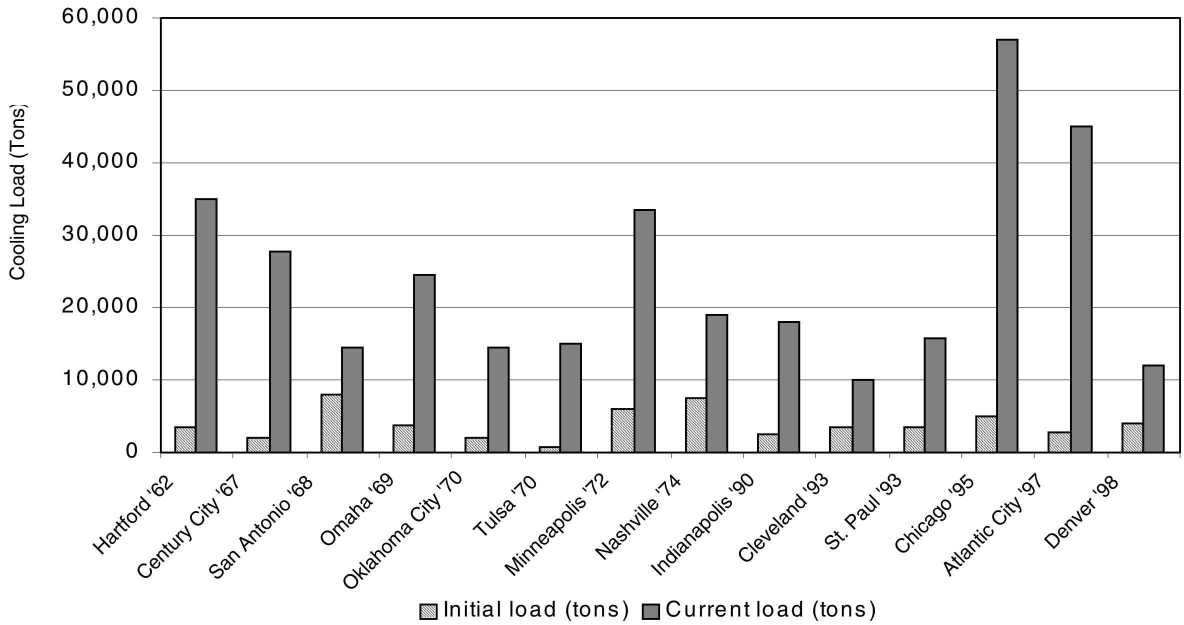
District energy systems are a growing market for CHP. DES distribute steam, hot water, and/or chilled water from a central plant to individual buildings through a network of pipes. DES provide space heating, air conditioning, domestic hot water, and/or industrial process energy. DES represent an important CHP market because these systems significantly expand the amount of thermal load potentially served by CHP. In addition, DES aggregate lower temperature thermal loads than many industrial process loads, enabling more cost-effective CHP. As discussed previously, low temperature loads allow increased electricity production compared with CHP systems producing higher temperature industrial process heat. District energy systems may be installed at large, multi-building institutional campuses such as university, hospital, or government complexes or as merchant thermal systems providing heating (and often cooling) to multiple buildings in urban areas. The addition of CHP to existing district energy systems represents an important area for adding new electricity generation capacity (Spurr 1999).

Since the late 1970s, numerous utility-owned district steam systems have been purchased by companies whose sole business is DES. These specialists have invested heavily in upgrading existing systems to improve their reliability, efficiency, and cost-effectiveness. The industry's recent growth has not been limited to the revitalization of existing systems. New systems have been constructed by DES utility companies, including for-profit and non-profit corporations, publicly owned municipal utilities, and investor-owned electric and gas utilities. Electric utility companies that have chosen to keep their steam systems have done so because they view them as key parts of their utility service business.

Many major utility companies have entered the district energy business in the last five years, generally with unregulated subsidiaries operating district cooling systems using thermal storage. The new players include subsidiaries of Unicom Corp. (formerly Commonwealth Edison), Boston Edison, Reliant Energy (formerly Houston Industries), Entergy, Conectiv (formerly Atlantic Energy), Cinergy, New Century Energies (formerly Public Service Company of Colorado), and Baltimore Gas & Electric. Others are actively evaluating opportunities.

Phase-out of ozone-depleting refrigerants has motivated building owners to opt for cost-effective alternatives such as district cooling. Simultaneously, electric and gas utilities are increasingly implementing district cooling systems as competition increases for retail energy customers, as discussed above. Once district cooling systems are established, they grow substantially, as illustrated in Figure 14.

Figure 14. Growth of Selected Utility District Cooling Systems, Showing First Year of Operation. Source: Spurr (1999).



District energy systems in the United States primarily serve commercial and institutional buildings, although some systems serve multi-unit residential buildings. Data on the use of energy in commercial buildings is surveyed by the EIA every three years (EIA 1997c). This Commercial Buildings Energy Consumption Survey (CBECS) provides the following data:

- Out of a total of 58.77 billion square feet (BSF) of commercial building space in 1995, 5.94 BSF (10.1 percent) used district heating and 2.52 BSF (4.3 percent) used district cooling.
- 24.35 BSF (41.4 percent) of all commercial building space was found in multi-building facilities, with 7.25 BSF (12.3 percent of the total) in multi-building facilities served by a central physical plant, e.g., a district energy system.

To obtain additional information about the use of DES in the United States, DOE's Office of Utility Technologies obtained data from various associations and surveys of DES users to perform a national characterization study in 1992 (DOE 1993). Key findings of the survey of 652 district energy systems conducted for this study were:

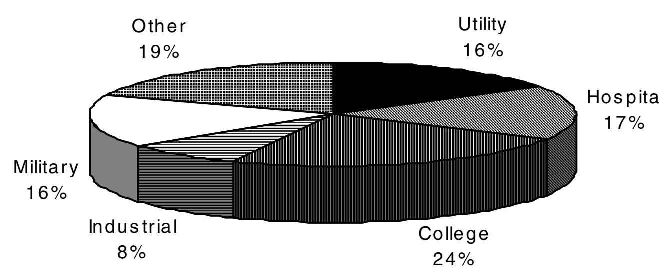
- Steam was the predominant type of energy produced and distributed by the surveyed systems, accounting for about three-quarters of the total energy production. Chilled water represented about 15 percent, with hot water and electricity accounting for less than 5 percent each.

- Natural gas is the major source of energy, providing 46 percent of the total energy, with coal providing 22 percent and electricity, fuel oil, and renewable sources providing 21 percent, 9 percent, and 1 percent, respectively.
- The median surveyed system served between 11 and 50 buildings, with a total combined floor area in these buildings of more than two million square feet.

Based on the survey and other data sources, the Census study developed the following estimates for the total population of DES in the United States:

- About 5,800 DES are currently in operation.
- DES collectively represent about 800 billion Btu per hour of installed thermal production capacity and provide over a Quad of energy annually — about 1.3 percent of all energy used in the United States each year.
- Delivered through more than 20,000 miles of pipe, this energy is used to heat and cool almost 12 billion square feet of enclosed space in buildings that serve a diverse range of office, education, health care, military, industrial, and residential uses.
- Utility systems, which sell heating and/or cooling services to a number of independent building owners, represent only 2 percent of the total number of U.S. systems but were responsible for about 16 percent of all estimated district energy production. All remaining facilities are institutional systems, composed of a central plant and distribution network to serve buildings owned or managed by a single organization. These institutional systems account for 84 percent of total U.S. production capacity, including 24 percent in colleges or universities, 17 percent in hospitals, 16 percent in military installations, and 8 percent in industrial facilities (see Figure 15).

Figure 15. District Energy Output by System Type . Source: DOE (1993).



New district energy systems that incorporate CHP typically will require several years to develop because of the time and complexity involved in developing the district energy piping network. As a result, the near-term potential from CHP in new systems is limited.

The DOE (1993) projected that 10 percent of DES use CHP. This report did not estimate the amount of CHP generation capacity in DES. Utility Data Institute (UDI) data on non-utility CHP facilities indicates 1,319 MW_e capacity in 244 educational institutions (UDI 1995) . UDI also estimates 215 MW_e of CHP supplying district energy systems and an additional 1,074 MW_e of CHP in 251 facilities in a variety of categories including health services and public administration (including military), most of which are likely to be combined with DES. The total likely district energy CHP, based on UDI numbers, is 2,608 MW_e in 525 facilities. However, based on other data, the UDI numbers appear low.

The District Energy web site maintained by the University of Rochester (1999) lists 107 individual CHP systems in colleges and universities. The total generating capacity of the systems on this list, which is an incomplete list of college/university CHP systems, is over 1,500 MW_e, exceeding the UDI estimate for educational institutions noted above. In addition, there is an undocumented amount of CHP capacity in other types of DES (primarily merchant systems serving downtown areas). For example, Trigen Energy Corp. operates a number of CHP facilities in Philadelphia, Pennsylvania (150 MW_e), Nassau County, New York (57 MW_e), and Trenton, New Jersey (12 MW_e). The largest district heating system in the United States, operated by Consolidated Edison in New York, New York, relies significantly on CHP.

Although the data are incomplete, the existing CHP capacity in DES can be estimated based on available information to be 3,500 MW_e, or 8 percent of the 1995 total CHP capacity of 45,100 MW_e (EIA 1996a). Base case growth (without favorable policies) in DES CHP by the year 2020 is likely to be in the range of 1,500 MWe.

Buildings

With the arrival of low-cost, high-efficiency reciprocating engines, and the prospect of cost-effective, micro-combustion turbines, CHP is now becoming potentially feasible for smaller commercial buildings. This area, sometimes called “self-powered” buildings, involves the installation of a system that generates part of the electricity requirement for the building while providing heating and/or cooling. Packaged systems, such as the reciprocating engines from Waukesha and Caterpillar, have a capacity beginning at 25 kW_e. This size range makes it possible to install CHP in smaller commercial applications, like fast-food restaurants, as well as larger commercial buildings. The principal limitation of reciprocating engines is the low temperature of the reclaimed heat, which is only sufficient to drive a single-effect absorption chiller.

Fuel cells and micro-turbines are likely to expand this market further because of their high temperature heat production (Kaarsberg et al. 1998). On the other hand, there may be a limit to smaller CHP systems, at least based on existing technology. A recent study from England indicates that operational labor costs can make systems less than 100 kW_e uneconomic (Strachan and Dowlatabadi 1999). This limitation can be avoided by installing small-scale district energy systems. The authors envision these as systems designed to service a small group of buildings. The heating and cooling loads can be aggregated to produce an economic size load.

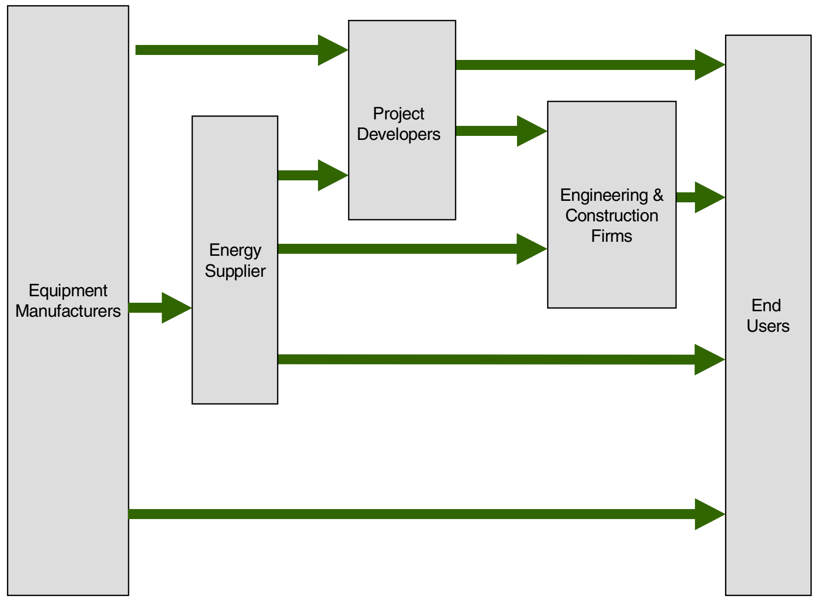
The total capacity contributed by this segment will be modest for the next few years since these systems are so small and the market infrastructure for distributing, installing, and operating these systems is still developing. Buildings, however, represent an important mid- to long-term market (Kaarsberg et al. 1998).

Market Players

While no recognized CHP market structure currently exists, the authors see a market structure beginning to develop. Besides these end-use markets, four major categories of players are emerging (see Figure 16):

- Project developers
- Equipment manufacturers
- Engineering and construction firms
- Energy supply companies

Figure 16. Conceptional View of the CHP Market.



These groups offer a range of alternatives from design/build to build/own/operate to comprehensive energy supply/services.

Project Developers — Much of the recent interest in CHP has been driven by companies that specialize in designing and building systems. Some of these companies are comprehensive solution providers, offering customers financing and own/operate agreements. Companies focusing on larger systems, such as Edison Mission Energy, Calpine and EUA Congenix, have also been involved in development of IPP power-only systems. Trigen Energy Corp. has been the most visible and aggressive developer of mid-sized systems, focusing on the own/operate market for industrial and institutional markets. Trigen has also been an active player in the district energy market, matching these thermal loads with cogeneration systems.

Equipment Manufacturers — Equipment manufacturers, from boiler makers to turbine manufacturers, have been increasingly active in marketing CHP. Clearly, their interest is in expanding markets for their products. Gas turbine and engine manufacturers, like Solar Turbines, Allied Signal, Caterpillar, Tecogen and Waukasha, have been the most aggressive. Some like Tecogen have actively marketed packaged systems. More recently some fuel cell manufacturers, such as Ballard, ONSI, and Siemens-Westinghouse, have begun to link their technologies to CHP.

Engineering and Construction Firms — During the last period of interest in CHP during the late 1970s and early 1980s, engineering firms played a key role in identifying potential customers for CHP. Some of the smaller, regional engineering firms worked on smaller systems, frequently with existing clients. Most systems were designed and built by large national or international engineering firms for large industrial and institutional end-users. This model remains true today, with most of the systems involving national engineering firms. Only a few of the regional firms have yet to enter the market.

Energy Supply Companies — The unregulated subsidiaries of some traditional utilities, both gas and electric, have entered the CHP market. Some gas utilities, like Brooklyn Union Gas, have seen CHP as an opportunity to compete with electric utilities for the industrial market. Some electric-only utilities, like the Mission Energy division of Edison International and EUA Cogenix, entered the market during the cogeneration boom of the late 1970s and early 1980s. Others, like Cinergy and Northern Indiana Public Service Company, have begun developing CHP projects as part of their expansion into the energy service market. Some electric utilities have seen CHP as an opportunity to expand their markets outside their regulated service territory. With the recent trend toward mergers leading to combined electric and electric utilities, these two approaches are likely to converge.

At this point no single group of market players dominates, although many recent projects seem to involve electric utilities in some capacity. Different parties are frequently partnering with other groups to develop and implement projects. For example:

- Trigen, a leading project developer, has partnered with Cinergy Solutions to identify and install CHP projects at industrial, district energy, and institutional sites across the country (Hall 1998).
- Allied Signal, an aggressive equipment manufacturer, has partnered with a number of electric utilities to market and install their micro-turbine-based packaged generators, which could be used for CHP (Price 1998).
- Duke Energy, a utility that has been a leader in expanding into non-regulated markets, has partnered with Fluor Daniel, a major engineering and construction company, to install/own/operate large CHP projects at institutional and industrial sites.

The structure of this delivery market is rapidly evolving. Various alliances are continuing to form, with strategies constantly in flux. One element that does appear to be emerging is that more innovative utilities are likely to play an increasingly important role in this market, often in competition for customers with some of the more traditional utilities. The increasing involvement of some utilities in the CHP market offers hope that some of the hurdles mentioned above (e.g., excessive interconnection requirements and prohibitive "exit" fees) could diminish as utilities join rather than fight the CHP bandwagon.

V. REGULATORY AND MARKET HURDLES TO CHP

Although technologies used in CHP systems have improved in recent years, significant hurdles exist that limit widespread use of CHP. Importantly, these hurdles have the effect of tending to "lock in" continued use of polluting and less-efficient electricity generation equipment. The main hurdles to CHP are:

- A site-by-site environmental permitting system that is complex, costly, time consuming, and uncertain.
- Current regulations do not recognize the overall energy efficiency of CHP or credit the emissions avoided from displaced grid electricity generation.
- Many utilities currently charge discriminatory backup rates and require prohibitive interconnection arrangements. Increasingly, utilities are charging (or are proposing to charge) prohibitive “exit fees” as part of utility restructuring to customers who build CHP facilities.
- Depreciation schedules for CHP investments vary depending on system ownership and may not reflect the true economic lives of the equipment.
- The market is unaware of technology developments that have expanded the potential for CHP.

In addition, development of new district energy systems as part of a CHP implementation face some additional barriers as discussed below.

Environmental Regulations and Permitting

Historically, the regulation of air emissions in the United States has been tied to input-based standards. This approach measures the level of a criteria pollutant (for example, nitrogen oxides) emitted per unit of fuel input. Alternately, it measures the concentration of a pollutant in the exhaust gas stream, with volume varying with fuel input. Reduction strategies have focused on adding an “end-of pipe” control technology, such as a collector or scrubber, to meet the targets set by the regulations. In addition, the major focus has been placed upon new sites, which can more easily meet the regulations, with less emphasis on existing emitters. This approach has given us terms such as “new source performance standards,” “new source review,” and “best available control technology (BACT),” which reflect the focus on new facilities and end-of-pipe control.

This existing regulatory framework does not provide credit for efficiency in generation of usable energy, and perversely, may encourage operation of inefficient and highly polluting facilities because they are “grandfathered” under the Clean Air Act. Old, dirty plants continue to operate decade after decade, emitting tens of times more pollution per kWh_e than new plants. In addition, the existing permitting system is structured to deal with large utility generation facilities, not small CHP facilities distributed throughout a region. As a result, the permitting process can be long, costly, and involved, sometimes taking several years. The emissions level that the facility may be required to meet is not determined until the end of the process.

A regulatory environment that credits efficiency must focus on “net” emissions. Much as with the efficiency discussion in Section III, the emissions from a CHP system must be compared with the emissions from the separate generation of power and heat. Thus, while the on-site emissions at the CHP site may be increased, the net emissions will be lower because of the displaced emissions from separate generation of electricity and thermal energy. This concept is embodied in output-based standards, where the emissions are calculated based on usable output from a system rather than fuel input.

Some of these policies are beginning to change. In both the revisions to the New Source Performance Standards (NSPS) rule and the State Implementation Plans (SIP) call, both signed by the EPA Administrator in September 1998, provisions are made for moving to output-based emissions standards. The EPA is investigating how output-based emissions standards can be implemented in other regulatory areas as well (Bailey 1998).

However, the NSPS rule sets a bad precedent by devaluing the thermal output, crediting only half the value of the thermal output. Fortunately, a simple solution preserves the policy goal without requiring a change in the calculation and only a minor change in the explanation of the rule. A weighted average of the electric-only and thermal-only emission rates, based on the system’s electric and thermal output, could be used to determine the allowable emissions.

This problem results from the view of some policy makers that electricity is the highest value energy source. While it is true that electricity takes more fuel to produce than any other energy source, the flexibility of electricity may be unnecessary for many energy applications. For example, electric hot water heating has an efficiency *at the end-use site* that approaches 100 percent. Gas-fired boilers have end-use efficiencies of 60 to 85 percent. However, because of the inefficiency in electricity generation and transmission, overall efficiency for electric hot water is about 30 percent. The goal is to match the “quality” of the energy with the use, and use the lowest quality energy source to maximize the overall efficiency of utilization. For CHP this may mean shifting a current electric load, like cooling, to thermal energy. The shift can have profound impacts on overall efficiencies, although the end-use efficiency might not appear to justify the use of the technology.

If output-based standards are implemented, efficient CHP facilities can probably avoid installing expensive control technologies required for electricity-only generation facilities. Total emissions of pollutants would be reduced from the level resulting from separate heat and power generation.

However, the challenge is not just to have the EPA issue clear guidance on CHP permitting but also to have the states implement the guidance. Our environmental regulatory system is based around state environmental quality agencies implementing regulations that achieve the environmental quality targets set in national regulation. As a result, it may take years for EPA guidance to be reflected in state regulation and practice.

Grid Access

While the concept of connecting a CHP facility to the grid may seem straightforward, it is complicated by both technical and regulatory issues. These issues are further complicated by the variety of system interconnection configurations. Three general configurations exist:

(1) The site sells all the electricity it generates and purchases all the electricity it requires. This represents the PURPA model, with the purchase price set at the utility "avoided cost." This system was developed in the days before real-time electricity pricing, when fixed rate schedules were used to set the price of electricity. Most CHP facilities will not find this attractive since avoided costs today are usually quite low. In addition, facility operators do not have the flexibility to vary generation to avoid purchase of power during high-cost periods.

(2) The facility uses all the electricity internally and purchases additional power to make up any difference. This is the pre-PURPA scenario. It is relatively simple, requiring only one meter and a means to insure that electricity does not flow back onto the grid.

(3) The facility purchases electricity at some times and sells electricity at other times. This scenario can be the most complex, since it requires metering and conditioning of the power flows for both sales and purchases, but may be most financially attractive to the system operator. The operator may choose to purchase power from the grid when it is cheaper than on-site generation and elect to sell power during peak price periods, even if it requires curtailment of on-site usage. Selling power at a high price, for only a few hours a year, can result in a significant revenue stream. Peak electricity prices of more than $1 per kWh_e were seen in the Midwest during the summer of 1998, when the cost of CHP-generated electricity would have been only a few cents per kWh_e.

"Net metering" is one variant of this configuration. About 20 states have implemented it for small renewable energy systems, such as solar and wind power. Size capacity limits vary from 10 to 100 kW_e. The utility installs a meter that can run in both directions depending upon on-site generation and use. While the simplicity of the system is appealing, its widespread implementation on larger systems is unlikely to be viewed with favor by utilities. With net metering the customer is effectively selling back at the full retail price including the transmission charges.

The site avoids many of these issues if it disconnects from the electricity grid. While some sites that install CHP can do this, these are very much the exception. Most sites will require a permanent connection to the grid to:

- Insure a reliable supply of electricity in case of an outage of the on-site generation,

- Provide a source of additional electricity to meet requirements in excess of the available on-site generation capacity, and
- Provide a market for any excess power generated by the CHP system.

We can group these interconnection issues into three categories: technical, nontechnical, and restructuring-induced.

Technical Interconnection Issues — The interconnection of a facility with on-site generation to the electricity grid must synchronize the voltage and frequency of the on-site generation with power from the grid. They must also implement means to handle, in a safe and orderly manner, the unscheduled loss of power from either source. These protections include preventing "back powering" of the grid if there is an outage, which could pose a safety risk to both utility workers and the public. This equipment also protects on-site equipment from damage caused by power disturbances resulting from the two sources of generation.

Technology exists for dealing with all these issues and developments in power electronics have improved the quality and reduced cost of interconnection. However, a consistent standard for implementing these interconnects does not exist. Many utilities have chosen to be overly cautious, or sometimes uncooperative, in specifying interconnects so that the cost and uncertainty have become a barrier to on-site generation.

Technical interconnection standards are under development by several national organizations, such as Institute of Electrical and Electronic Engineers (IEEE). It appears, however, that work is focusing on smaller systems and that final standards for larger systems may be several years away. The Clinton Administration has recognized this problem and has included provisions in its proposed restructuring legislation that would direct the DOE to speed up the development of standards.

Nontechnical Interconnection Issues — Interconnection contracts will have several components. Electricity demand above the on-site generation will be priced as would any other service, with both an energy and a demand component. However, the power that may be required to backup the on-site generation will be priced differently. The utility must make investments in both generation reserves and T&D to meet this eventuality. The pricing needs to allow them to recover these costs since there is not an ongoing demand for this power that can be used to recover the cost. Unfortunately, there has been little consistency in how these prices are set by utilities. Some utilities have set these interconnection and standby charges at levels that will make on-site generation uneconomic.

In addition, a utility may charge a facility that installs on-site generation an "exit" fee. Regulators have intended this fee to recover investments made by the utility to service customers in anticipation of their future demand for power, such as T&D capacity, transformers, and other infrastructure. In some cases, these fees can be at levels that will make CHP uneconomic. While there may be a legitimate justification for recovering some of these investments, some utilities have chosen to include many costs in these fees that are difficult to justify. In addition, regulators have not afforded other businesses, like telephone companies, the opportunity to charge exit fees, so it is unclear why they should afford electric utilities this right.

Electric Utility Restructuring Issues — Electric utility restructuring has resulted in a set of fees that utilities are allowed to charge to cover the cost of transition (often called competitive transition charges or CTCs). These fees can be used to recover the cost of uneconomic investments ("stranded costs"), such as nuclear power plants. While these fees are only temporary, the charges can be substantial. A new CHP facility may be required to continue to pay these charges based on their historical usage even if they no longer are using the power. Some states (such as Pennsylvania) will even require new CHP facilities serving a new load to pay these fees even if the utility was never asked to provide service. Other states (such as California and Massachusetts) have appreciated the value of CHP and have exempted CHP facilities from a significant portion of these fees. Other states should follow this lead.

Also, some utilities (in states such as Colorado and New York) have been given additional rate flexibility. They have used this flexibility to offer price breaks to facilities considering on-site generation. These rates are frequently well below those charged other customers and are usually sufficient to discourage the installation of a CHP facility.

These hurdles result in part because no national guidance exists for either the technical or nontechnical interconnection of distributed generation. The Federal Energy Regulatory Commission (FERC) has indicated that it does not have jurisdiction over these issues except with respect to PURPA qualifying facilities. As a result, jurisdiction resides with the states, which have limited resources to draw upon to develop their policies. The combined result of these interconnection issues is that costs, delays, fees, and pricing strategies combine to discourage the installation of CHP systems. Since utility interests have succeeded in blocking solutions to these issues in many states, federal legislation would be useful to address these issues in a uniform way.

Depreciation and Ownership Issues

CHP systems do not fall into a specific tax depreciation category but rather can fall into several categories depending upon configuration and ownership. This can result in depreciation periods ranging from five to 39 years. For example, when a combustion turbine or reciprocating engine is used in a mobile application, such as a ship, it can be depreciated over five to seven years. If the same unit is used for stationary power generation, it is depreciated over 15 years. If a boiler is used to capture the heat in the exhaust, the depreciation period increases to twenty years, and if it is installed as part of a building, it is depreciated over a 39-year period (Casten 1998). These depreciation rates are based upon past history, in which stationary engines were used either for standby operation at a customer facility or as a peaking unit by an electric utility. In either case, the equipment would be operated for only a few hundred hours per year. In CHP facilities, these same engines are operated for thousands of hours per year, usually at a high fraction of their design capacity. Historically, boilers used for space or process heating were designed to operate for years.

They were intended to be regularly repaired and refitted. Modern heat recovery steam generators are less costly but may be operated under much more extreme conditions, such as lower exhaust temperatures, resulting in more frequent maintenance. In CHP systems, the maintenance costs for equipment can approach the initial purchase cost of the machine in the seven- to ten-year period, so the longer depreciation schedules currently applied no longer reflect the economic reality.

In addition, different ownership situations can result in the equipment being put in different categories. For example, while an industrial facility may be able to depreciate CHP equipment that is owned and operated to satisfy on-site power and heat requirements over a 15-year period, the same equipment, owned and operated by a third party that sells the heat and power to a facility, would depreciate the equipment over at least a twenty-year period. We anticipate that future CHP facilities will use these alternative financing strategies, especially third party ownership or leasing arrangements, to address the capital requirements associated with installing a system. Existing depreciation policy may foreclose some ownership strategies, discouraging installation of CHP systems.

In its proposed 1999 utility restructuring bill, the Clinton Administration has begun to acknowledge this problem. The bill proposes to reduce the depreciation period for CHP equipment in commercial rental and owner-occupied buildings from 27.5 and 39 years, respectively, to 15 years (DOE 1999b). This change is a major step. It is now up to those interested in CHP to demonstrate to the Internal Review Service and the Treasury that other CHP equipment should have its tax life adjusted. Alternatively, federal legislation should be enacted that standardizes depreciation for CHP equipment at seven to ten years independent of ownership.

Lack of Awareness

Current awareness of CHP is dominated by experiences with cogeneration from the late 1970s and 1980s. Most individuals that the authors have spoken with define cogeneration as boilers and steam turbines. There has been no systematic education about the developments that have occurred that have expanded market potential and improved the financial attractiveness of CHP systems. In addition, the changes in the electricity industry, such as a move to real time pricing and increasing T&D congestion, have created new opportunities for CHP that have only recently begun to be highlighted. As a result, owners of good sites for CHP may not be aware of the potential that exists for them.

District Energy Hurdles

Accelerated development of new district energy systems in a non-institutional environment can be realized by addressing barriers relating to awareness, information and education, economics and financing, and infrastructure planning and regulation.

Awareness — People and organizations who could be key stakeholders in implementing DES are generally not aware of the potential benefits.

Perceptions — Outdated perceptions of district energy still influence decision-making today.

Information and education —

- Even if city officials, building owners and others are aware of district energy and its benefits, they generally lack the expertise necessary to facilitate the implementation of these systems.
- Development of a new DES is a complex under-taking, involving many institutional, technical, legal, and financial issues.

Capital Cost — High initial capital costs and the time and risks associated with developing a mature DES are significant constraints.

Uncertainty and Risk –

- While district energy is a proven and reliable energy service technology, its benefits are accrued over an extended period.
- A new system or expansion of an existing system is often burdened by high debt service costs in the early years, before a broad base of customers has been connected to the system.
- As a result, it is often difficult to finance new systems, despite their long-term benefits to their communities and the environment.

Accounting for Total Costs and Benefits — District energy substitutes for far more than the fuel and electricity used for heating and cooling, but all of the cost benefits are not always understood.

Lack of Integrated Planning — Decisions about power plant capacity, solid waste management, environmental quality, local economic development, and other critical issues are generally not made in an integrated fashion.

Franchise Fees — The structure of local franchise fees often places district energy at a competitive disadvantage relative to other energy systems.

Thermal Density — Land-use development patterns, and plans and regulations governing them, do not always encourage the high thermal densities or mixed use patterns most conducive to a DES.

Siting Issues — While new DES distribution technologies can economically and efficiently transport energy over greater distances than previously possible, plant siting can raise "NIMBY" problems.

State Utility Regulatory Issues — Rate regulation is unnecessary but continues to burden many systems.

VI. Potential Impacts of Expanded Use of CHP

The DOE and the EPA have set a target of adding almost 50 GW_e of CHP capacity in the United States by 2010. A first question that must be posed is, "Is this realistic?" In this section we look at the potential for CHP in various market segments and how quickly this potential can be implemented. In addition, we project the resulting energy, money, and emissions savings.

Assessment of the potential involves the development of a *base case* in which current regulatory and market conditions persist, and a *policy case* in which policies have been implemented to remove the hurdles identified in Section V.

Base Case

We have chosen to use the EIA *Annual Energy Outlook* (EIA 1998) projection for new cogeneration additions as the starting point for developing our base case. Two new additional sources shed further light on what is likely to happen in the current policy environment. The first is a baseline assessment of cogeneration in the industrial sector prepared for the Gas Research Institute (EEA 1998). The GRI estimates a higher current installed base of CHP than is shown by EIA. This study, however, agrees with the EIA projection of a declining rate of future capacity additions. In addition, Spurr (1999) examined deployment of CHP in district energy systems and projected the potential for additional CHP in this sector. By combining these three sources, ACEEE has developed a baseline for CHP (see Table 5 and Figure 17).

Estimating the CHP Potential

Estimating the potential for increased CHP is made difficult because of the diversity of system types and potential sites. It is anticipated that much of the early capacity will occur at larger industrial and institutional facilities that already have boiler systems and thermal distribution infrastructures (e.g., district energy systems). Sometimes a steam turbine can be added to the existing system, while in other cases an existing boiler may be repowered with a combustion turbine. Many of these boilers are reaching the end of their economic life (Roop and Kaarsberg 1999) and adding CHP represents an opportunity to install modern, efficient replacement equipment. As time progresses, smaller industrial, institutional, and commercial facilities will begin to make up a greater part of the new capacity. New district energy systems, which aggregate the thermal demands of several facilities or buildings, will take longer to become a major factor in CHP because of the time required to develop and grow the piping network.

Table 5. CHP Capacity Base Case (MW_e generating capacity)

	Historical Industrial (EEA 1998)	Industrial Base Case (EEA 1998)	District Energy Base Case (Spurr 1999)	Total Base Case*
1980	9,800			9,800
1985	17,000			17,000
1990	28,500			28,500
1995	44,028	44,028	3,500	47,528
2000		51,042	3,800	54,842
2005		52,913	4,100	57,013
2010		54,168	4,400	58,568
2015		55,504	4,700	60,204
2020		56,839	5,000	61,839

* No estimate is available for the district energy base before 1995.

Several studies have attempted to define the technical, economic, and achievable potential for CHP. They have used various data sources and approaches. One approach uses the steam generation capacity in the inventory of boilers (Bluestein 1998; ICF Resources 1997; Interlaboratory Working Group 1997; Major and Davidson 1998; Roop and Kaarsberg 1999). Using assumptions regarding the form of CHP implemented and economics of operation, the additional electric generation potential (in megawatt-hours electric) from CHP is estimated. Another approach has been to use annual steam generation data (Alliance to Save Energy et al. 1997; Bernow et al. 1997; Laitner 1997; Roop and Kaarsberg 1999). These are combined, with assumptions about boiler operating characteristics and average ratio of electricity to steam production, to estimate how much electricity could be generated. From this value, the additional electric generation capacity can be estimated.

In the fall of 1997, the DOE and the EPA convened a group of experts[5] to compare their analyses and develop a single consistent estimate of the potential for CHP. Using a Delphi approach, investigators agreed on a technical potential of at least 160 GW_e of new, CHP-based electricity generation above current EIA estimates. They estimated 50 GW_e could be installed by 2010. The experts agreed that the total "economic" potential to reduce carbon emissions exceeded 100 MMT_{CE}, with the "achievable" CHP by 2010 yielding 30 to 40 MMT_{CE} (DOE 1997).

Since the DOE and EPA estimates were developed, several other data sources have become available. These include a district energy system study, mentioned above (Spurr 1999), an

[5] Experts: David Bassett, DOE; Steve Bernow, Tellus Institute; Joel Bluestein, Energy and Environment Analysis; Peter Carroll, Solar Turbines; Keith Davidson, ONSITE Energy Corp.; Neal Elliot, ACEEE; Mark Hall, Trigen; Tina Kaarsberg, Northeast Midwest Institute; Skip Laitner and Joe Bryson, EPA; and Mark Spurr, International District Energy Association.

assessment of the potential for small-scale CHP in the residential and commercial buildings sectors (Kaarsberg et al. 1998), and assessments of CHP potential in industry (Roop and Kaarsberg 1999; ONSITE 1997a, 1997b). ACEEE combined these assessments with the consensus estimates from the fall of 1997 to develop the projects reported in Table 6 and Figure 17. Since the average industrial CHP project will require 3 to 5 years to implement (Carroll 1998; Davidson 1998), the 2000 estimate assumes zero additions to the baseline. The 2020 value is assumed to be 90 percent of the economical potential from the consensus estimate.

It is assumed that most of the potential between now and 2010 would use existing technologies. However, as noted in the technology section of this report (Section III), need continues for development of new technologies. Small-scale technologies (e.g., those less than 500 kW_e) are especially in need of work to reduce cost and pollution, and improve efficiency and reliability. Small-scale technologies are particularly important in the building sector but significant potential also exists in the industrial and district energy markets. For example, the average industrial facility has an electricity demand of less than 300 kW_e (EIA 1997b). Figure 18 shows projections of the share of future CHP additions that would come from existing and new technologies.

Figure 17. Projected Additions to Installed CHP Capacity under the Base Case and Policy Cases (see text for source information).

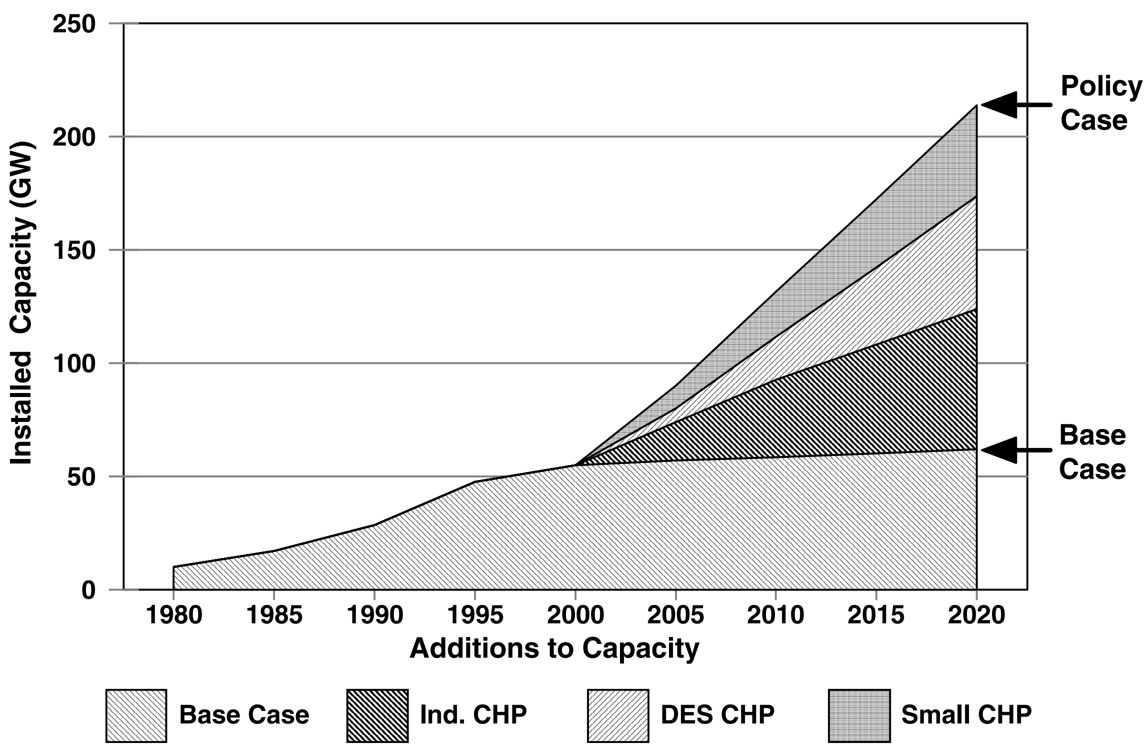


Table 6. Additions to CHP Capacity in Policy Case

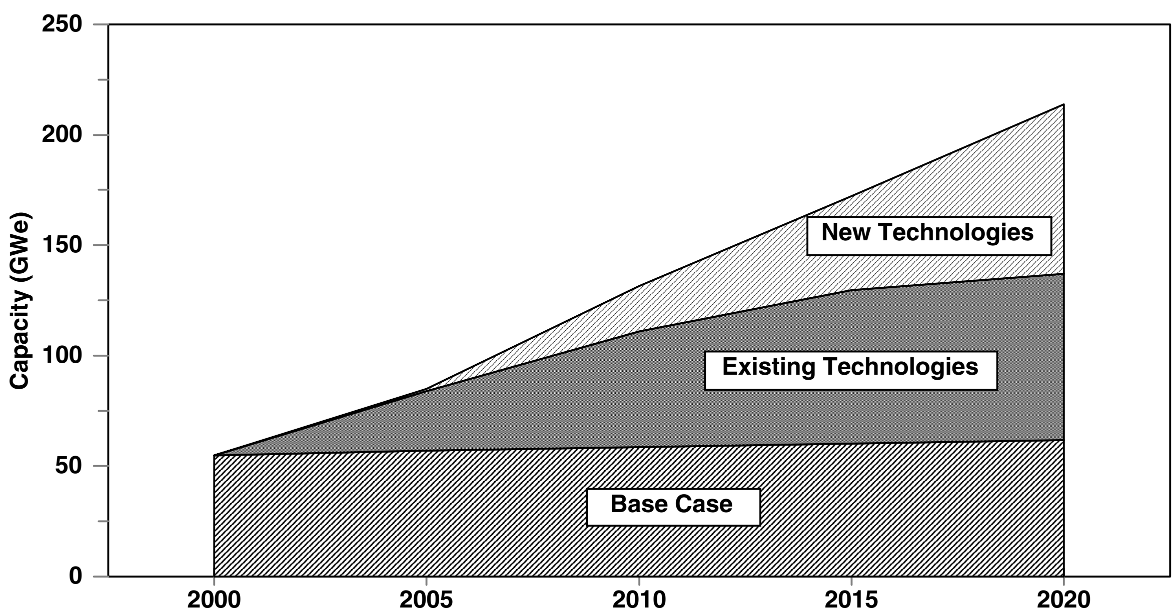
(MW_e additions to generating capacity above base case)

	Industrial CHP (ACEEE)	DES CHP (Spurr 1999)	Small-Scale CHP (Kaarsberg et al. 1998)	Total Policy Case
2000	0	0	0	0
2005	17,000	6,000	5,000	28,000
2010	34,000	19,000	20,000	73,000
2015	48,000	34,000	30,000	112,000
2020	62,000	50,000	40,000	152,000

Energy Savings, Emissions Reductions, and Capital Expenditure

Based on these estimates of additions to capacity, projections were made of the energy savings, emissions reductions, and capital expenditures. This report only presents the analysis methodology for CHP in the industrial sector. Spurr (1999) used a similar approach to calculate the same information for district energy systems. While the analysis for the small-scale CHP was approached similarly (Kaarsberg et al. 1998), too much uncertainty existed in the data, so projections were only made for energy and carbon savings. Table 7 presents totals for industrial and district energy systems, and totals including the available data for small-scale systems.

Figure 18. Role of Technology in Additions top CHP Capacity



The overall system efficiency of a CHP system ($\boldsymbol{\eta}_{\mathbf{system}}$ from Equation 1 in Section III) varies with the configuration. Efficiencies range from 50 percent (for systems that cannot make the most effective use of the thermal energy) to more than 80 percent (for thermally optimized systems). The overall system efficiency also varies with the power-to-heat ratio ($\boldsymbol{\alpha}$ from Equation 4), with the most efficient systems having power-to-heat ratios of less than 0.5.

General Assumptions — The average overall system efficiency in our analysis is assumed to be 70 percent, with an average power-to-heat ratio of 0.5. This implies a power efficiency ($\boldsymbol{\eta}_{\mathbf{power}}$ from Equation 3) of 23 percent and a thermal efficiency ($\boldsymbol{\eta}_{\mathbf{thermal}}$ from Equation 2) of 47 percent. The net power heat rate ($\boldsymbol{h}_{net\,power}$ from Equation 6) is assumed to average 4,015 Btu per kWh_e.

To calculate the avoided utility generation, it is assumed that the CHP electricity generation capacity is operated 7,100 hours per year at 90 percent of its rated capacity. This operating profile assumes that the generation component of the CHP system is sized for the base thermal load of the facility, and thermal swings are met by supplemental firing of the boiler. In a restructured electricity market, other operational profiles may be more financially attractive but information and analyses currently available make it difficult to evaluate them. The incremental cost of CHP capacity, over and above a conventional boiler, is estimated to be $650 per installed kW_e (Bluestein 1998; Carroll 1998). The additional fuel required to cogenerate electricity was calculated assuming natural gas and using the assumed net electric heat rate as discussed above.

To calculate the impacts for the avoided utility generation, we assume that the CHP displaced the generation at the current average fossil generation heat rate (see Table 7). The average fossil heat rate was derived from EIA data (Geller et al. 1998). Based on data reported in the *Electric Power Annual* (EIA 1996b), it is assumed that the utility generation capacity would have been operated 6,000 hours per year at 67 percent of its rated capacity. The CHP capacity would displace new utility electricity generation. This generation is assumed be new gas, combined cycle generation, with a cost of $425 per installed kW_e (Bluestein 1998; Carroll 1998).

Estimating Energy Savings — The estimation of energy savings is a two-step process. First, an estimate is made of the utility-generated electricity displaced by CHP. Then an estimate is made of the additional fuel required by the CHP system to generate that electricity. Total electricity is calculated by multiplying the installed additional CHP capacity in a given year by the stated operating assumptions. The net energy savings are calculated by multiplying this electricity generation by the difference between the utility heat rate for fossil fuel plants and the CHP net power heat rate. Table 7 presents the results.

Cost savings are calculated by determining the cost of avoided electricity and subtracting the cost of additional fuel. We use the average national industrial pricing for the electricity specified in Table 8. These values are derived from the industrial sector projections made in the *Annual Energy Outlook* (EIA 1998).

Table 7. Impact of Additional CHP Capacity

	New Additional CHP (GW_e)	Displaced Util. Gen. (TWh_e)	Additional On-Site Fuel (TBtu)	Cumulative Additional Capital ($Mill)	Net Energy Savings (TBtu)	Net Savings ($mill.)	Carbon (MMT)	SO_2 (Mill. Tons)	NO_x (Mill. tons)
Industrial (ACEEE)									
2005	17	109	436	11,050	629	3,246	18.19	0.33	0.15
2010	34	217	872	22,100	1,214	5,918	34.31	0.65	0.29
2015	48	307	1,231	31,200	1,591	7,245	46.14	0.92	0.42
2020	62	396	1,590	40,300	1,995	8,825	56.62	1.19	0.54
DES (Spurr 1999)									
2005	6	47	189	4,630	200	860	7.10	0.25	0.12
2010	19	148	594	13,860	700	2,290	21.30	0.76	0.34
2015	34	265	1,064	18,060	1,100	3,850	35.90	1.27	0.57
2020	50	390	1,566	19,540	1,600	5,210	51.40	1.80	0.81
Total w/o Small CHP									
2005	23	156	625	15,680	829	4,106	25.29	0.58	0.26
2010	53	365	1,466	35,960	1,914	8,208	55.61	1.41	0.64
2015	82	572	2,295	49,260	2,691	11,095	82.04	2.19	0.99
2020	112	786	3,156	59,840	3,595	14,035	108.02	2.98	1.35
Small CHP (Kaarsberg et al. 1998)									
2005	5				240		4		
2010	20				480		17		
2015	30				720		26		
2020	40				960		35		
Total									
2005	28	156	625	15,680	1,069	4,106	29.65	0.58	0.26
2010	73	365	1,466	35,960	2,394	8,688	73.06	1.41	0.64
2015	112	572	2,295	49,260	3,411	11,815	108.21	2.19	0.99
2020	152	786	3,156	59,840	4,555	14,995	142.92	2.98	1.35

Table 8. Projected U.S. Gas and Electricity Prices and Average Fossil Electricity Generation Heat Rate

	Nat. Gas ($/MBtu)	Elec. ($/kWh$_e$)	Utility Heat Rate (Btu/kWh$_e$)
2000	2.73	0.043	
2005	2.77	0.041	9,800
2010	2.93	0.039	9,600
2015	3.00	0.036	9,200
2020	3.17	0.035	9,050

Sources: EIA (1998); Geller et al. 1998.

Estimating Emissions Reductions — In a similar manner to the cost calculations, emissions from the additional fuel are subtracted from the displaced utility electricity emissions. Projected emission factors in 2010 for both utility electricity and natural gas combustion are presented in Table 9.

Estimating Investment Costs — Because of the diversity of system configurations, permitting issues, system sizes, and construction approaches (repowering versus new construction) as well as difficulties separating electricity from thermal systems, generalizing about the incremental cost of electricity from CHP systems is difficult. Larger systems (greater than 50 MW$_e$) tend to have lower costs per unit of generation, often falling below $500 per installed kW$_e$. The installed cost for smaller systems can approach $1,000 per kWh$_e$, although sometimes the cost of permitting can approach a quarter of this cost. Based on interviews with experts (Carroll 1998; Davidson 1998; Hall 1998; Parks 1998), ACEEE has elected to use an installed cost of $650 per kW$_e$. This estimate represents a conservative assumption for two reasons. First, we anticipate most of the new capacity installed by 2010 will be relatively large systems. Second, bearing the full capital cost is not really fair to the CHP system since it is either being installed to replace an existing system or in place of a new thermal-only system.

Table 9. Emissions Factors (per TWh$_e$) as of 2010

	Grid Electricity	Additional Fuel*	Net
Carbon (MMT_{CE})	0.22	0.06	0.16
SO_2 (Mill. Ton)	0.0030	0.0000	0.0030
NO_X (Mill. Ton)	0.0019	0.0006	0.0014

* Assumed to be Natural Gas
Sources: EIA (1996b, 1998).

Impacts

It is clear from this analysis that the DOE and EPA target of 46 GW$_e$ of additional CHP capacity by 2010 is realistic. Excluding small-scale CHP, this analysis indicates that 53 GW$_e$ of new capacity could be installed by 2010 and 112 GW$_e$ by 2020. If the small-scale capacity is included, total potential capacity increases to 73 GW$_e$ in 2010 and 152 GW$_e$ in 2020. In 2010, the industrial and district energy system CHP capacity would result in net energy savings of 1.9 quads and emissions reductions of almost 56 MMT_{CE}. Achieving these savings would require a cumulative investment of almost $36 billion. Including the small-scale CHP increases the energy savings to 2.4 quads and carbon reductions to 73 MMT_{CE}. As a result, CHP could contribute to more than 10 percent of the U.S.'s Kyoto carbon reduction target.[6]

VII. Policy Mechanisms to Stimulate CHP

The DOE's goal of doubling CHP capacity by 2010 is far greater than any growth projected under the base case policy and trends. If the DOE's target is to be met, new policies are needed to address the hurdles that currently constrain CHP in the marketplace. New policies are needed at both the state and federal levels, as well as in the private sector.

Environmental Permitting

Environmental permitting for CHP systems is complex, costly, time consuming, and uncertain. Air pollution permits are required from state environmental authorities before plant construction can begin. Current environmental regulations do not recognize the overall energy efficiency of CHP or credit the emissions avoided from displaced electricity generation (Casten 1998). The focus should be shifted toward minimizing the emissions needed to meet society's' energy needs. Regulations should be revised to take into account the efficiency of the generating system. A major barrier to change is the share of emissions current tied up in the electric utility sector. Regulations and policies should be reformed to allocate emissions to the cleanest and most efficient systems preferentially.

The United States should move toward an output-based system of environmental permitting that will regulate emission per kWh_e or Btu of useful energy output. In doing so, *all* units of useful energy — both power and thermal output — should be included. CHP does not need an advantage, just a level playing field. The EPA should develop recommendations and guidance to state regulators on output-based standards and should provide technical assistance to states in implementing these standards. There will, of course, be challenges in implementing this policy, created in part by our existing permitting system that allocates rights to emit to existing facilities. Nevertheless, steps should be taken to end the current inequitable system, where older, dirty power plants are allowed to emit hundreds of times as much as newer, cleaner plants and where CHP plants receive no credit for their high efficiencies.

The current permitting system, which was developed to address a market for large, centralized electric and power generators, needs to be restructured to better meet the needs of smaller,

[6] Reducing U.S. carbon emissions to 3 percent below 1990 levels by 2010 (a level consistent with the overall Kyoto target) would require a total reduction of about 484 MMT_{CE} from projected carbon emission in 2010 (EIA 1998)

distributed energy systems. Developers should be allowed to start building CHP systems at their own discretion, with operation dependent on complying with air pollution rules.

Since much of the new capacity will use modular components, consideration should be given by the EPA to certificating the emissions performance of specific equipment models such as engines and turbines. This certification would allow for expedited permitting by the states. The EPA should review the permitting process with a focus on achieving environmental goals with as little time and uncertainty for the permit applicant.

While the EPA can recommend new procedures, it will be up to state environmental agencies to implement this policy. The federal government should provide both guidance and encouragement to state regulators to implement these measure locally. State and federal regulators should also consider establishing programs to facilitate permit applicants seeking to install clean, efficient technologies.

Electric Grid Access

As noted earlier, most CHP facilities will need to connect to the electricity grid. It will be important to insure that this process is fair and expeditious. On the technical side, the DOE and the FERC should establish national technical standards for interconnection to the grid. State regulators should require their transmission and distribution companies to use these standards. Any customer that meets these standards should be allowed to connect to the grid immediately.

On the non-technical side, FERC and state regulators should ensure that CHP facilities are given fair and reasonable access to the electricity grid for purchase of stand-by power and sale of power to the grid without unreasonable fees. While the FERC has only acknowledged jurisdiction over PURPA qualifying facilities, it is reasonable that it should assume leadership on insuring open assess as part of its implementation of Order 888 creating a competitive marketplace. Distributed generation assets will play a crucial role in a competitive electricity marketplace.

FERC, state regulators, and state legislatures should insure that stranded asset exit fees are not used as a means of discouraging new CHP facilities. States should follow the lead of Massachusetts and California, which have exempted CHP from these fees. Even under the most ambitious projections, the cost of this exemption would be modest, and the benefits from expanded CHP would more than compensate for the cost. However, these exemptions should not be conditional upon type of ownership. All CHP facilities should be treated on an equal basis.

CHP System Depreciation

The depreciation of CHP assets needs to be modernized to reflect economic realities of current markets and technologies. The Clinton Administration has recognized problems with the current system. It has proposed, in its restructuring legislation (DOE 1999b), to reduce the deprecation period for CHP systems in buildings to 15 years from its current, clearly unrealistic levels of 27.5 and 39 years. The U.S. Treasury and Internal Revenue Service should continue its review of CHP system assets. A specific category should be created for CHP equipment; this category should be consistent and not treat different ownership situations differently. We recommend that this period should be set at 7 to 10 years, reflecting the current economic life of modern CHP technologies, such as gas turbines and reciprocating engines.

Financing and Incentives

While we are convinced that on a level playing field, CHP systems are cost competitive, incentives may be needed in the current environment. These incentives could take the form of tax credits, grants, or low-cost loans. The need for help is particularly true for public sector facilities, which frequently face major capital availability barriers. The federal and state governments should consider establishing loan pools that could be used to implement CHP at government and non-profit institutions, and also consider financing of new district energy systems.

The Administration has proposed an investment tax credit for CHP systems, as part of their FY2000 budget (Treasury 1999). The proposal calls for an 8 percent investment tax credit for CHP projects installed during the 2000 to 2002 tax years. While the credit is modest, it will likely raise awareness and tip the balance toward CHP for a number of projects under consideration. There are two issues that diminish its cost-effectiveness:

- Because CHP projects can take several years from inception to service, it is unlikely that many of the projects during the first year or two of the credit will be incented by the credit. Were the credit period to be delayed by a year (i.e., to cover the 2001 to 2003 tax years), more time would be allowed to develop projects that could take advantage of the program and the share of “free riders” would be reduced.
- Providing credit for larger systems (those above 50 MWe) appears unnecessary because these systems have been proven to be economic and are being installed. If the credit were limited to smaller systems, a higher credit could be offered for these systems that currently face the most significant cost barriers. We suggest that the upper limit on the credit be set at a level of about 50 MW_e. We would suggest increasing the credit into the 10 to 20 percent range, which would create much more of an incentive. Also, since the development of projects becomes more challenging as the system size decreases, the credit level should be increased as the size decreases. For example:

System Size	Credit
25-50 MW_e	10%
10-25 MW_e	15%
< 10 MW_e	20%

Education and Technical Assistance

The federal government and the private sector should coordinate their educational and technical assistance activities. Potential customers should receive clear and consistent information. While much is known about CHP, many questions need to be addressed and tools need to be developed. Of particular importance are:

- case studies of CHP projects providing full technical and financial details,
- widely available tools for evaluating the potential for CHP at a facility, and
- guidance for sites considering CHP on the regulatory and permitting process.

The DOE has taken the first steps in addressing these needs by establishing the CHP Challenge program. This program is intended to provide information and decision-making tools to potential CHP sites and to state governments to help them in developing their own CHP programs. The Challenge efforts are being coordinated with the newly established U.S. Combined Heat and Power Association. The Association's members include equipment manufacturers, public interest groups, project developers, and end-users. These represent promising developments. However, much more needs to be done. State governments and state and regional organizations, such as state energy agencies and regional energy efficiency initiatives (e.g., Northwest Energy Efficiency Alliance and Northeast Energy Efficiency Partnerships), should become involved in education efforts and technical assistance.

Technology Research and Development

While significant potential exists from currently available technologies for CHP in the near term, there is a need for additional technology development. As noted earlier in this report, current technologies can only satisfy a portion of the small-scale CHP market. Cleaner, more efficient, and more cost-effective small-scale systems are needed if the full potential in this market area is to be realized. The federal government should continue to fund research and development in small-scale CHP technologies.

Demonstration

The federal government has a unique opportunity to promote CHP and save taxpayers money by installing systems at government facilities such as military bases, federal buildings, hospitals, and prisons. Likewise, state and local governments should also commit to installing CHP systems in their facilities where cost-effective. In order to move forward, federal, state, and local governments should commit to evaluating all their facilities for CHP potential and implementing those that are shown to be cost-effective.

District Energy Systems

In addition to the above measures, the following activities should be undertaken to catalyze the development of new district energy systems and the implementation of CHP in existing DES.

Local Government Outreach — Implement a local government outreach campaign to:

- increase awareness of the benefits of district energy by local governments and community stakeholders;
- assist communities in evaluating potential district energy opportunities in downtown areas or in redevelopment projects such as brownfields revitalization; and
- provide technical assistance to facilitate the implementation of new systems through public/private partnerships.

Energy Provider Outreach — Implement an energy provider outreach campaign to:

- increase awareness of the potential strategic benefits of CHP and district energy for utilities and power producers in a changing business and regulatory environment;
- provide information on existing "thermal sinks" for CHP; and
- facilitate public\private partnerships for implementing CHP and district energy systems by linking private sector power producers with local governments that have identified opportunities for district energy systems.

Technology Transfer — Disseminate information about district energy technologies and provide design tools to architects, planners, and engineers, including training materials, technical guidebooks, and computer simulation tools. This information should address how district systems work, how to integrate them into development plans and designs, and how to integrate CHP with district energy systems.

VIII. CONCLUSIONS

Combined heat and power can contribute to the transformation of the United States' energy future. CHP offers significant, economy-wide energy efficiency improvement and emissions reduction potential. Our existing system of centralized electricity generation charts an unsustainable energy path, with increasing fuel consumption and carbon emissions, while continuing to squander over two-thirds of the energy contained in the fuel. At least half of this wasted energy could be recaptured if we shift from centralized generation to distributed systems that cogenerate power and thermal energy. Besides saving energy and reducing emissions, distributed generation also addresses emerging congestion problems within the electricity transmission and distribution grid.

CHP represents an opportunity to make significant progress towards meeting our Kyoto commitments on greenhouse gas reductions. The local air quality improvements and opportunities for economic growth presented by CHP are equally compelling. CHP presents an opportunity to improve the "bottom line" for businesses and public organizations, while also providing a path for improving the environment.

During the last two years, CHP has become an important element of the national energy debate. The United States has taken the first steps toward setting in place policies to promote CHP by establishing a national target. The DOE and the EPA have begun to review the means for achieving this target. The target now needs to be translated into concrete policies and programs at both the federal and state levels for overcoming the significant hurdles to greater use of CHP. New policies should be adopted to:

- Facilitate environmental permitting of new CHP projects;
- Establish output-based emissions standards giving full credit to both thermal and electrical output;
- Facilitate access to the electricity grid for CHP systems, including adopting interconnect standards and eliminating onerous "exit fees" and standby power requirements;
- Provide standardized depreciation at 7 to 10 years for all classes of CHP ownership;
- Expand educational and promotion activities;
- Widely implement CHP systems at government facilities, where cost-effective; and
- Catalyze the development of new district energy systems.

The private sector also needs to take a leadership role. The primary barriers to much greater CHP use are regulatory and institutional, not technical or economic. The private sector must work with government regulators and policy makers to insure that competition and incentives for innovation are preserved, while creating a favorable regulatory environment for CHP. And the private sector should actively pursue adoption of CHP — both for environmental and "bottom-line" benefits.

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