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COMBINED HEAT AND POWER DESIGN GUIDE

ASHRAE®

COMBINED HEAT AND POWER DESIGN GUIDE

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This publication is accompanied by the ASHRAE CHP Analysis Tool, which can be found at www.ashrae.org/CHPDG. These files take a unique approach to solving the issue of obsolescence of equipment databases by allowing the user to input the parameters for the CHP system characteristics independently of the technology selection and providing reliable, transparent cost savings results from the application of CHP. If the files or information at the link are not accessible, please contact the publisher.

CHAPTER 1

CHP FUNDAMENTALS

1.1 INTRODUCTION

Historically, combined heat and power (CHP) design guides have focused on design and development features of major system components, including reciprocating engine internal structural and wearing surface design, combustion turbine aerodynamics, microturbine recuperator flexural modulus, and heat exchanger design fouling factors. Although these elements are critical to develop high-performing and reliable components, they are not of particular interest to an engineering practitioner seeking to understand and apply a CHP system to a specific application. This design guide provides application and operational information about prime movers, heat recovery devices, thermally activated technologies; technical and economic guidance regarding CHP systems design, site screening and assessment guidance and tools; and installation, operation, and maintenance advice.

It is the authors' intention to furnish a design guide that provides a consistent and reliable approach to assessing any site's potential to economically use commercially available CHP systems.

This book is accompanied by a new ASHRAE CHP Analysis Tool and a chapter on an exergy approach to CHP, which can be found at www.ashrae.org/CHPDG. These files may be used for assessing sites for CHP applicability. If the files or information at the link are not accessible, please contact the publisher.

1.2 OVERVIEW

Combined heat and power (CHP), also known as cogeneration, is the sequential generation of usable heat and power (usually electricity) in a single process. The electricity is generated at or close to the end-use, allowing the capture and use of the resulting waste heat for site applications. CHP systems generate electricity and useful thermal energy in a single, integrated system. CHP is not a technology, but an approach to applying technologies. Heat that is normally wasted in conventional power generation is recovered as useful energy, avoiding the losses that would otherwise be incurred from separate generation of heat and power.

Central station generation is inherently inefficient, only converting on average about a third of the input fuel's potential energy into usable energy. Engineers have long appreciated the tremendous efficiency opportunity of combining electricity generation with thermal loads in buildings and factories, capturing much of the energy that would otherwise be wasted. When the term "CHP" was coined in the 1970s to describe this practice, the dominant configuration of systems was a boiler that generated steam, some of which was used to turn a steam turbine that generated electricity. Because of the cost and complexity of these systems, they were largely confined to systems of over 50 MW, thus precluding their installation at most manufacturing facilities. Recent advances in electricity-efficient, cost-effective generation technologies—in particular, advanced combustion turbines and reciprocating engines—have allowed for new configurations of systems that combine heat and power production, expanding opportunities for these systems and increasing the amount of electricity they can produce.

Two powerful policy drivers will likely increase demand for CHP systems and assessments over the next decade: the increased availability of cheap natural gas supplies from shale deposits, and increased attention by energy users on the need to reduce operating costs.

CHP's unique place between energy suppliers and consumers, its provision of two types of useful energy, and its interaction with electricity networks mean that its prospects necessarily remain tied to local regulation and the quality of public policies that remove barriers and promote its uses.

1.3 HISTORY

Dating from the 1880s, when steam was still the primary source of motive power in industry and electricity was just emerging as a product for both power and lighting, industrial plants led in the application of CHP concepts. The use of such technology became commonplace as engineers replaced steam-driven belt-and-pulley systems with electric power and motors, moving from mechanically powered systems to electrically powered systems. In the 1890s, before the development of the electric grid and almost of necessity, industrial applications cogenerated. Power was used in motors and steam for thermal purposes. There were no regulated utilities, and CHP was simply a power technology. In the 1900s, most of the power used by industry was cogenerated.

With the evolution of the electric utility industry, purchased power costs dropped while power reliability and quality increased. As technology developed, leading to larger central plants and their resulting economies of scale, utilities were able to deliver more capacity for each dollar invested. Moreover, the higher efficiencies achieved at these plants resulted in lower fuel costs as natural gas demand decreased.

The development of the integrated grid provided several additional benefits to end users. First, the grid resulted in increased reliability, as power was made available from a number of sources and not just a single generating plant. Second, the average cost of power dropped as the available capacity was operated on an economic dispatch basis. That is, the lowest cost plant available to satisfy a requirement was loaded first, thus lowering the average cost of power production. Third, low-cost oil and gas and increases in coal productivity resulted in still lower generation costs.

In general, industrial users found that the most effective way to satisfy power requirements was to purchase it from the local utility. The perception that electric power generation was a natural monopoly requiring exclusive service areas and cost regulation also gave some end users a sense that power was being made available at the lowest price. Additionally, the low fuel costs caused industrial energy users to ignore conservation opportunities, typically resulting in the installation of less costly and less efficient boilers, because the incremental costs of high-efficiency boilers were not judged to be cost effective. Ultimately, the typical energy end user chose to purchase power, decreasing the amount of cogenerated power.

While the overall trend in the amount of cogenerated power was downward, there were several cases, as in the oil and gas industry, refineries, chemical plants, or the pulp and paper industry, where CHP was both technically and economically compatible with process requirements; industrial sites continued to cogenerate, but at a much lower capacity. At these sites, several factors, including the availability of process by-products as fuel, the need for large quantities of steam at different pressures and temperatures, long operating hours, and the availability of qualified maintenance and operating personnel, facilitated the development and operation of CHP systems. In general, these systems took two forms: larger systems that typically sold the cogenerated power to the local utility or smaller systems (characteristically less than 5 MW) that used the power internally, reducing power purchases. These CHP systems were primarily based on either a backpressure or an extraction steam turbine. In addition, many electric utilities with power plants located in urban areas developed steam district-heating systems, with the source of the steam being large CHP systems at these central plants.

Utility rate and franchise regulation, which began in the early twentieth century and which became increasingly pervasive, acted to further discourage nonutility generators, as did the public utilities themselves, which sought to deter alternative suppliers in their own service areas. In fact, state and federal regulations sometimes resulted in CHP system financial structures that were unique partnerships of industrial and utility parties. With an exclusive franchise for power sales in its service area, electric utilities were sometimes able to impose restrictions that further reduced the cost-effectiveness of CHP. The overall impact was that the amount of CHP power produced in the US decreased steadily through the 1970s.

There was a short revival of interest in CHP in the late 1960s and early 1970s as the natural gas industry attempted to expand its market, particularly nonseasonal use, by encouraging on-site generating systems. Resistance from the electric utility industry, which was frequently evidenced as a refusal to interconnect the utility grid to sites that operated CHP systems or, if the site was interconnected, through high-cost supplemental and standby service, resulted in these sites operating totally independent of the electric utility grid. Referred to as “total energy systems” (TES), they consisted of on-site engine generator sets that served all of the site’s electrical requirements, with the end user’s thermal requirements being satisfied with heat produced by a prime mover, a supplemental boiler, or both. TES enjoyed some initial successes and began to enjoy greater acceptance in the early 1970s; however, the gas shortages and price increases of the 1970s and competitive marketing and rates from electric utilities resulted in a failure to develop the market further.

The history of CHP in the United States has been marked by important federal legislation. CHP received an important policy boost with the Public Utilities Regulatory Policy Act (PURPA) of 1978, which gave certain CHP facilities a guaranteed market for their power. This bill helped build a robust fleet of CHP systems across the country and marked the first time that federal legislation actively sought to encourage distributed generation and CHP. Figure 1-1 shows the significant increase in CHP installations in operation as a result of PURPA, beginning in the early 1980s and ending in the early/mid 2000s.

While PURPA promoted CHP development, it also had unforeseen consequences. PURPA was enacted at the same time that larger, more efficient, lower-cost combustion turbines and combined cycle systems became widely available. These technologies were capable of producing greater amounts of power in proportion to useful thermal output compared to traditional boiler/steam turbine CHP systems. Therefore, the power purchase provisions of PURPA, combined with the availability of these new technologies, resulted in the development of very large merchant CHP plants designed for high electricity production.

For the first time since the inception of the power industry, nonutility participation was allowed in the U.S. power market, triggering the development of third-party CHP

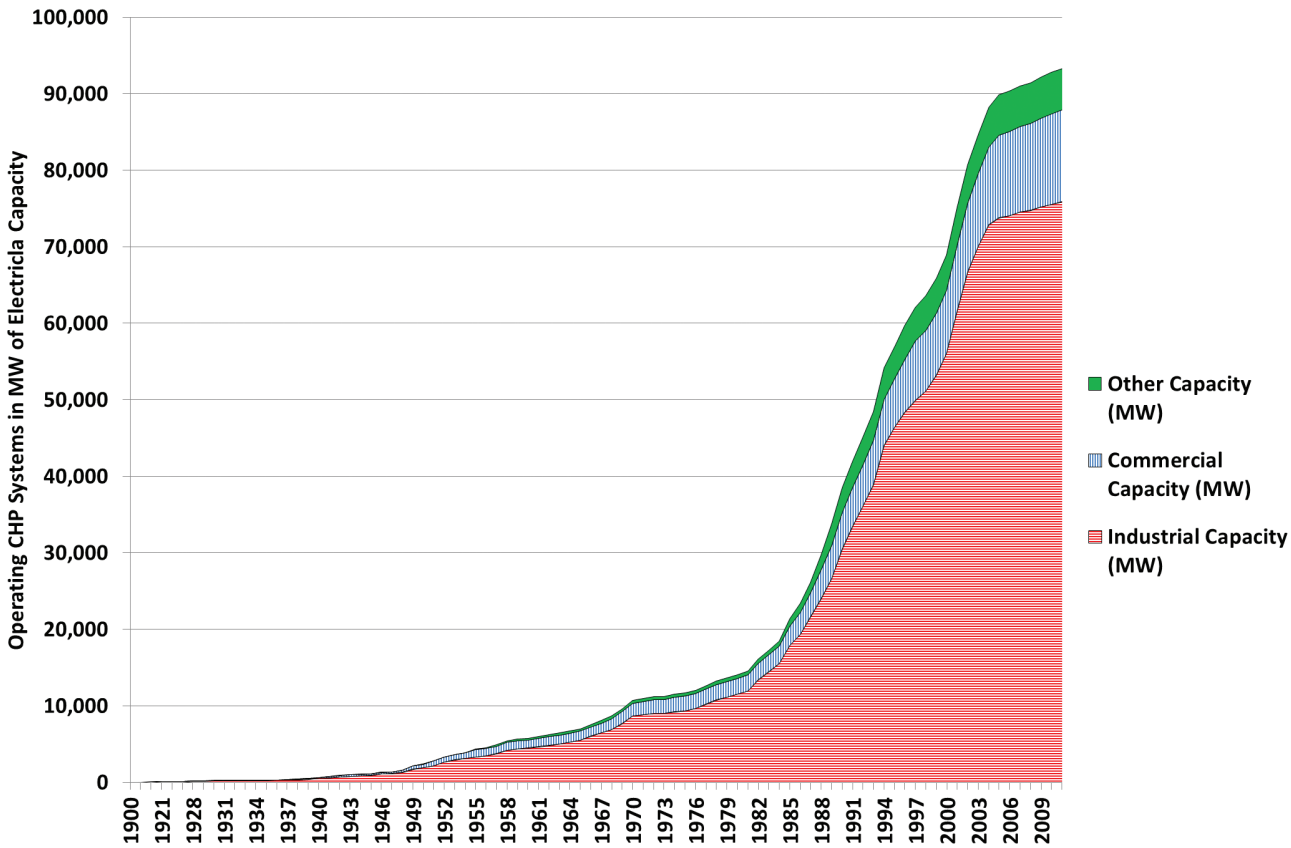


Figure 1-1. *Installed and Operating CHP Systems in the United States*[1]

[1] Source: ICF Combined Heat and Power Installation Database.

developers who had greater interest in electric markets than thermal markets. As a result, the development of large CHP facilities (greater than 100 MW) paired with industrial facilities increased dramatically; today almost 65% of existing U.S. CHP capacity—55,000 MW—is concentrated in plants over 100 MW in size[2].

By the turn of the century, natural gas deregulation was complete, and natural gas commodity markets were affecting the price of natural gas. Figure 1-2 shows a period of relatively stable natural gas prices in the late 1990s, followed by several periods of large price spikes after 2000. During 2008, natural gas spot prices traded as high as $13.32 per million cubic feet ($0.38 per million cubic metres) and as low as $5.63 per million cubic feet ($0.16 per million cubic metres). The large price fluctuations in 2008 increased the focus on price volatility and its impacts on natural gas market participants. Price volatility increased the uncertainty of natural gas pricing and dramatically impacted CHP adoption for much of the decade.

On August 8, 2005, the Energy Policy Act of 2005 (EPAct 2005) was signed into law. Section 1253(a) of EPAct 2005 added a new section 210(m) to the Public Utility Regulatory Policies Act of 1978 (PURPA) that provided for termination of an electric

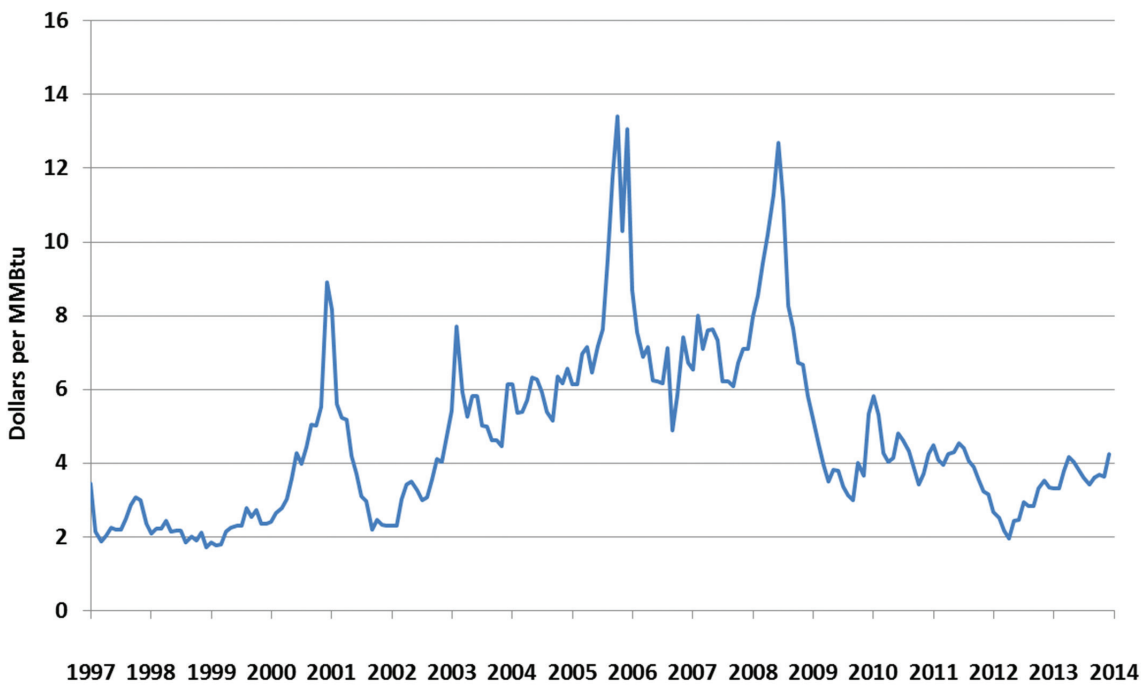


Figure 1-2. *Henry Hub[3] Spot Prices for Natural Gas 1996–2008[4]*

[2]Advancing Near-Term Low Carbon Technologies, The International CHP/DHC Collaborative, International Energy Agency. 2009.

[3]The Henry Hub is a distribution hub on the natural gas pipeline system in Erath, Louisiana, owned by Sabine Pipe Line LLC. Because of its importance, it lends its name to the pricing point for natural gas futures contracts traded on the New York Mercantile Exchange (NYMEX).

[4]Natural Gas Price Volatility. Randy Roesser, California Energy Commission. 2009.

utility's obligation to purchase energy and capacity from qualifying CHP facilities and qualifying small power production facilities (QFs), including CHP facilities, if the Federal Energy Regulatory Commission finds that certain conditions are met. This act removed federal feed-in tariffs for CHP plants and essentially put a significant drag on the expansion of CHP systems nationwide.

Utilities interested in retaining their electric customer bases are generally not incentivized to support greater CHP, because new CHP projects would reduce customer demand. If they are to actively support the increased development of CHP in their service territories, electric utilities will require some external incentive or mechanism to recover the lost revenue associated with greater CHP deployment. Few utilities have these incentives or mechanisms in place.

The North American shale gas revolution is entering a new phase of activity, with gas production in the "Big 7" U.S. shale gas plays (Antrim, Barnett, Devonian, Fayetteville, Woodford, Haynesville, and Marcellus) now estimated to be on track to rise to between 27 and 39 Bcf/d[5] (0.76 and 1.1 Bcm/d[6]) over the next decade. The Marcellus field is now the world's second largest natural gas field. Although some uncertainty exists with respect to the actual amount of economically recoverable shale gas reserves, the impact of shale gas production over the next decade, according to the EIA reference case, projects the Henry Hub spot market price remaining within $1.00 per million Btu ($0.29/MW) of its current price, $4.03 (May 2013). This new level of stability is an important factor in assessing opportunities for CHP moving forward.

1.4 CHP TRENDS

1.4.1 Policy

Energy policy today is a function of many issues, including assumptions about energy supply and demand, corporate interest, economics, market interest or disinterest, pollution fears, climate change, and politics. CHP is generally recognized as a positive approach to energy policy moving forward.

At the end of the 1990s, policymakers began to explore the efficiency and emission reduction benefits of thermally based CHP. They realized that a new generation of locally deployed CHP systems could play a more important role in meeting future U.S. energy needs in a less carbon-emissions-intensive manner. As a result, the federal government and several states began to take actions to promote further deployment of CHP. CHP has been specifically singled out for promotion by the U.S. Department of Energy (DOE) and U.S. Environmental Protection Agency (EPA).

The DOE in 2001 established the first of eight regional Clean Energy Application Centers to provide local technical assistance and educational support for CHP development. In 2001, the EPA established the CHP Partnership to encourage cost-effective CHP projects and expand CHP development in underutilized markets and applications.

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[5]Billion (10^9) cubic feet per day.

[6]Billion (10^9) cubic metres per day.

Several important federal programs have made significant contributions toward strengthening the CHP market. Most notable are the U.S. DOE Regional Clean Energy Application Centers and the federal CHP investment tax credit.

On August 30, 2012, a Presidential Executive Order was issued to accelerate investment in industrial energy efficiency. This Executive Order directs the Departments of Energy, Commerce, and Agriculture, and the Environmental Protection Agency, in coordination with the National Economic Council, the Domestic Policy Council, the Council on Environmental Quality, and the Office of Science and Technology Policy, to coordinate policies to encourage investment in industrial efficiency focusing on CHP. Specifically, these agencies are directed to, as appropriate and consistent with applicable law,

(a) coordinate and strongly encourage efforts to achieve a national goal of deploying 40 gigawatts of new, cost effective industrial CHP in the United States by the end of 2020;

(b) convene stakeholders, through a series of public workshops, to develop and encourage the use of best practice state policies and investment models that address the multiple barriers to investment in industrial energy efficiency and CHP; and

(c) utilize their respective relevant authorities and resources to encourage investment in industrial energy efficiency and CHP.

Federal focus and support encompassed within this Executive Order targeting increasing industrial CHP use will undoubtedly impact market adoption throughout the Federal sector, and influence state policy as well as the private sector.

Individual states also began to realize that a variety of policy measures were needed to remove the barriers to CHP development, and developed a series of policies and incentives, including streamlining grid interconnection requirements, simplifying environmental permitting procedures, and establishing rate-payer financed incentive programs for CHP deployment. Moving CHP into the energy policy mainstream and maximizing its potential benefits to society requires the continued development of these kinds of policies at the state level.

Evidence of short-timescale climate change is molding national and international policies to regulate greenhouse gases (GHGs) from sectors such as power generation, transport, industrial processes, waste disposal, and remediation. Criteria air pollutants, such as oxides of nitrogen (NO_x), carbon monoxide (CO), unburned hydrocarbons (HC), and particulate matter (PM) all have aftertreatment technologies that can reduce them into more benign compounds. Catalysts or combustion techniques can also reduce or eliminate GHGs, such as methane (CH_4) and nitrous oxide (N_2O). But, unfortunately, no catalyst is currently available for the most common and abundant GHG: carbon dioxide (CO_2). The industrial practice of carbon sequestration and storage, except through biomass, is neither mature nor widespread and also carries risks.

U.S. GHG emissions associated with fossil fuel electricity generation can vary from as low as 727 lb (330 kg) CO_{2eq}/MWh of generated electricity to almost 2000 lb (900 kg) of CO_{2eq}/MWh. There is potential for significant GHG reductions with CHP, depending on the installation location, yielding 314 lb (143 kg) of CO_{2eq}/MWh from a 4.6 MW recuperative combustion turbine, 419 lb (191 kg) of CO_{2eq}/MWh from a 2 MW lean-burn engine, and 649 lb (295 kg) of CO_{2eq}/MWh from a 2 MW a simple cycle combustion turbine and local GHG regulation policy. Future GHG regulations could be a strong driver for increased efficiency, and technologies such as CHP will be well positioned to meet the challenge.

1.4.2 Fuels

Historically, natural gas has proven to be the preferred fuel for CHP systems both large and small (Figure 1-3), and this trend is expected to continue largely because of the continuing development of shale gas in the United States.

Natural gas provides nearly one-fourth of the energy consumed in the United States and is expected to increase in the future. About 85% of the natural gas consumed in the United States is produced within U.S. borders; much of the rest comes from Canada, which also has a large natural gas supply base. Domestic natural gas production is expected to account for 80% or more of the total annual U.S. natural gas supply through the year 2030. Gas supplies are frequently described in two different ways: proved reserves, which are the estimated quantities of natural gas that current geologic and engineering data demonstrate to be recoverable under existing economic and operating conditions, and the total natural gas resource base, which is proved reserves plus

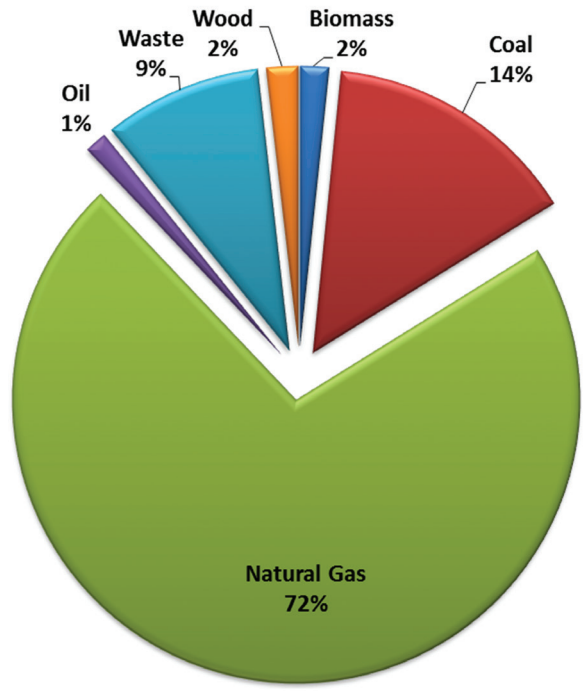


Figure 1-3. *Capacity (MW) of CHP by Fuel Type*[7]

[7] Combined Heat and Power Installation Database, http://www.eea-inc.com/chpdata/

undiscovered resources. The total U.S. natural gas resource base, including proved reserves, is more than 1500 trillion cubic feet (Tcf) (42.5×10^{12} cubic metres), providing a 75-year supply of natural gas at current production levels[8]. Natural gas pricing should remain stable and relatively low for a significant period of time as proven reserves increase. The important issue is the "spark spread"[9] over the operating or economic life of the CHP plant. Retiring central station power plants, tightening emissions regulations (e.g. the Utility MACT[10]), grid congestion, Smart Grid and other transmission and distribution upgrades all point to higher electricity costs. The one pressure on the natural gas price would come from increased use of natural gas for vehicles (likely but limited demand) and exporting liquid natural gas (LNG) from the United States.

Solid fuels, including refuse-derived fuel "waste," also make up a significant share of the market, although fuel- and ash-handling costs generally limit the use of solid fuels to systems of 10 MW or more.

1.5 CHP BENEFITS

To better understand CHP from a macroeconomic perspective, it is important to understand the benefits CHP can offer to two distinct groups: the owner of the system systems.

1.5.1 Benefits Realized by Owners of CHP Systems

Site owners generally value operating savings and sometimes value electricity reliability and power quality when assessing the economics of installing a CHP system. Rarely can they value other benefits that often accrue to society. CHP owner benefits are generally recognized as follows:

- **Reduced Operating Costs:** The principle owner's benefit from a CHP system is economic. Simply put, the total operating cost of the CHP plant, including fuel, maintenance and cost of capital, is less than the cost of purchased fuel and power, and these savings are significant enough to invest the capital to build the plant.
- **Increased Power Reliability:** Power reliability can directly impact the economic evaluation of a CHP plant. EPRI estimated the national cost of power interruptions, including power quality events, at $79 billion per year[11] (Figure 1-4).

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[8] Potential Gas Agency of the Colorado School of Mines, http://potentialgas.org/about .

[9] Spark spread is the relative difference between the price of fuel and the price of power. Spark spread is highly dependent on the efficiency of conversion. For a CHP system, spark spread is the difference between the cost of fuel for the CHP system to produce power and heat on site and the offset cost of purchased grid power.

[10] The emission standard for sources of air pollution requiring the maximum reduction of hazardous emissions, taking cost and feasibility into account. Under the Clean Air Act Amendments of 1990, the MACT must not be less than the average emission level achieved by controls on the best performing 12% of existing sources, by category of industrial and utility sources.

[11] The cost of power disturbances to industrial and digital economy companies. Report TR-1006274 (Available through EPRI). Madison, Wisconsin. Primen. 2001.

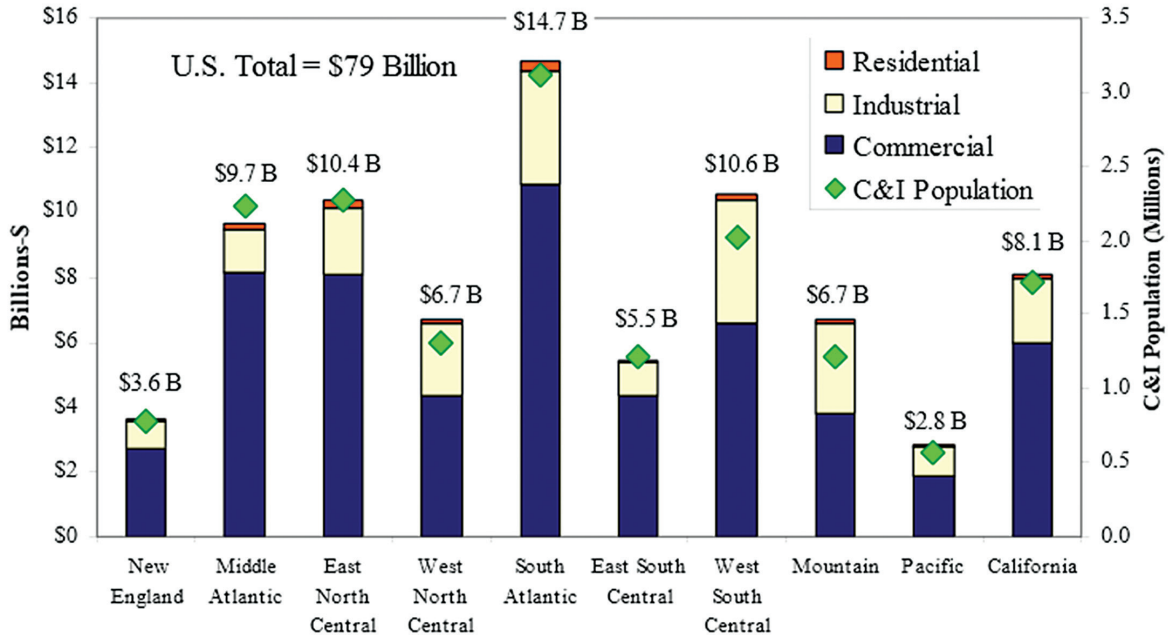


Figure 1-4. *Base Case Estimate: Cost of Power Interruptions by Region/Class*[12]

- **Reduced Peak Electricity Demand:** CHP can permanently reduce peak electric demand. Permanent reductions in electric demand can result in a one-time economic benefit to a CHP project. CHP generally does not qualify for demand response programs, unless the system is electrically oversized for the site load.

- **Offset Capital Cost:** CHP systems can offset capital costs that would otherwise be needed to purchase and install certain facility components, such as boiler and chiller systems in new construction. In addition, installing CHP systems with backup capability can enable a local government to avoid having to purchase a conventional backup electricity generator. Note that certain applications, such as hospitals, cannot use natural gas in the United States as a backup fuel source.

1.5.2 CHP Societal Benefits

- **Reduced Emissions:** CHP systems generally result in a reduction of pollutant emissions, including CO_2, NO_X, and SO_2, when compared to separately generated heat and power. The example below (Figure 1-5) shows results of a lean-burn engine/absorption chiller CHP system applied as base load power and cooling to a data center.

[12] Cost of Power Interruptions to Electricity Consumers in the United States (U.S.). Kristina Hamachi LaCommare and Joseph H. Eto. Lawrence Berkeley National Laboratory, U.S. Department of Energy. 2006.

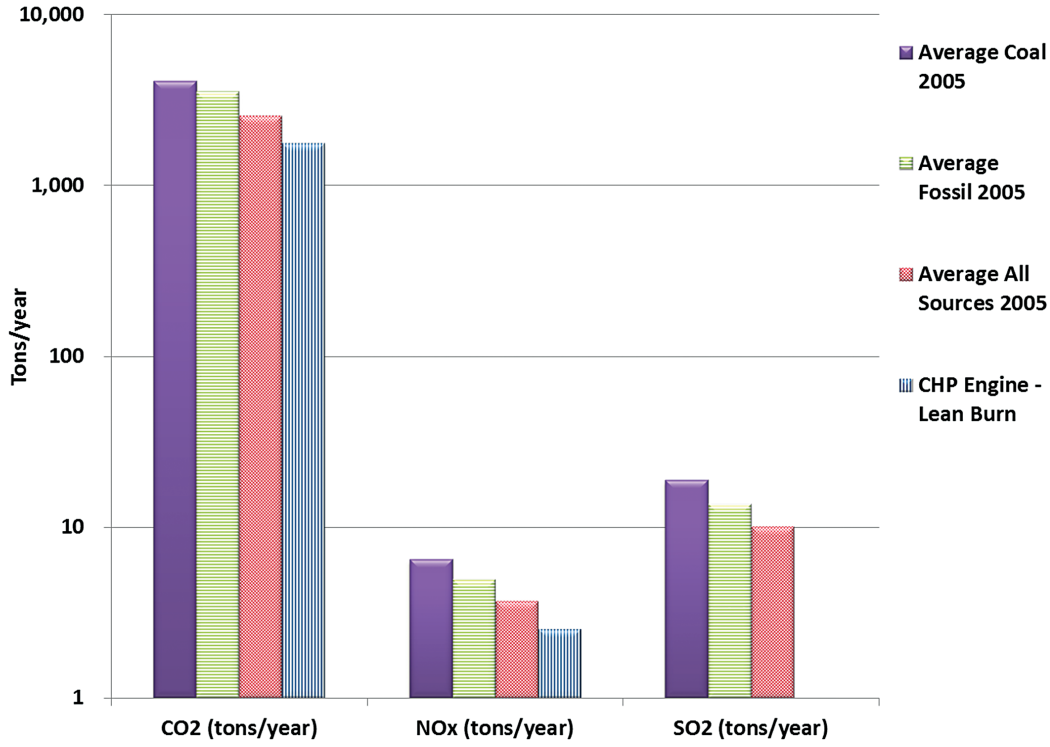


Figure 1-5. *Emissions from CHP Plant versus the National Grid*[13]

• **Energy Efficiency:** Energy efficiency (Figure 1-6) can be both a societal and an owner benefit. From an owners' viewpoint, properly designed and applied CHP systems save energy which means it should save energy cost. CHP makes more efficient use of primary fuel for producing heat and power than separate conventional methods, such as on-site boilers and power stations. Therefore, it can deliver significant environmental benefits and cost savings, given the right balance of technical and financial conditions.

• **Carbon Reduction Choices:** Table 1-1 compares the annual energy and CO2 savings of a 10 MW natural-gas-fired CHP system, separate heat and power with utility-scale renewable technologies, and natural gas combined cycle (NGCC) systems producing power only. This shows that CHP can provide overall energy and CO2 savings on par with comparably sized solar photovoltaics (PV), wind, and NGCC, and at a capital cost lower than solar and wind and on par with NGCC.

[13] Applying a Fuel and CO2 Emissions Savings Calculation Protocol to a Combined Heat and Power (CHP) Project Design. ASHRAE Winter Conference, February 2011.

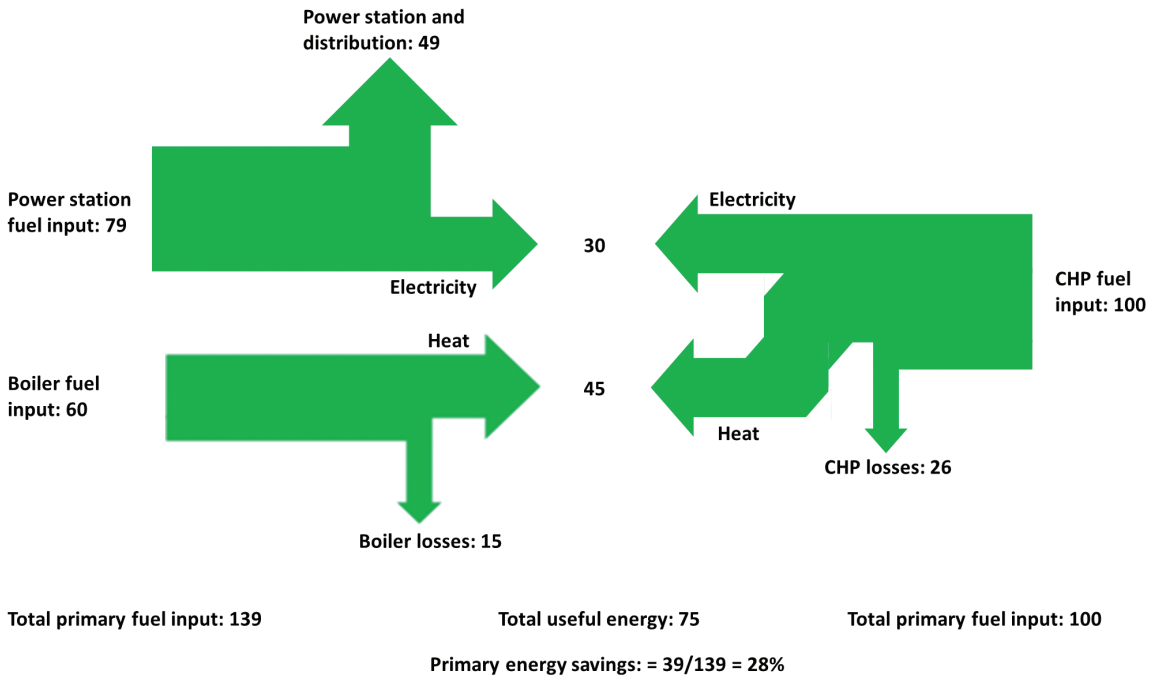


Figure 1-6. *Energy Savings of Typical Packaged CHP Compared to Conventional Sources of Heat and Power Generation (Shown in Units of Energy)*

Table 1-1. CHP Energy and CO_2 Savings Potential[14]

Category	10 MW CHP	10 MW PV	10 MW Wind	NGCC (10 MW Portion)
Annual capacity factor, %	85	22	34	70
Annual electricity, MWh_e	74,460	19,284	29,784	61,320
Annual useful heat, MWh_{TH}	103,417	None	None	None
Footprint required, ft^2 (m^2)	6000 (557)	1,740,000 (161 651)	76,000 (7061)	N/A
Capital cost, $	20,000,000	48,000,000	24,000,000	10,000,000
Annual energy savings versus today's grid, 10^6 Btu (MJ)	308,100 (325)	196,462 (207)	303,623 (320)	154,649 (163)
Annual CO_2 savings, tons (Mg)	42,751 (38 783)	17,887 (16 227)	27,644 (25 078)	28,172 (25 557)
Annual NO_x savings, tons (Mg)	59.8 (54.2)	16.2 (14.7)	24.9 (22.6)	39.3 (35.7)

[14] A Clean Energy Solution Combined Heat and Power. U.S. Department of Energy and U.S. Environmental Protection Agency. August 2012.

Assumptions:

1. 10 MW Gas Turbine CHP: 28% electric efficiency, 68% total overall efficiency, 15 ppm NO_x emissions
2. Capacity factors and capital costs for PV and wind based on utility systems in DOE's Advanced Energy Outlook 2011
3. Capital cost and efficiency for natural gas combined-cycle (NGCC) system based on Advanced Energy Outlook 2011 540 MW combined-cycle power plant
4. Combined cycle system proportioned to 10 MW of output, NGCC 48% electric efficiency, NOx emissions 9 ppm
5. CHP, PV, wind, and NGCC electricity displaces National All Fossil Average Generation resources (eGRID 2012): 9572 Btu/kWh, 1743 lb CO_2/MWh, 1.5708 lb NOx/MWh, 6.5% T&D losses; CHP thermal output displaces 80% efficient on-site natural gas boiler with 0.1 lb per million Btu NO_x emissions

• **Reduces Grid Congestion:** Industrial sites and urban centers are often capacity constrained. On-site CHP systems can deliver electric power, reducing peak power requirements.

• **Avoids Transmission and Distribution Costs:** On-site CHP systems can permanently avoid transmission, distribution, and central power generation upgrades, providing saving for all ratepayers.

• **Avoids New Generation Costs:** Each grid kilowatt saved generally saves the need for 1.09 kW of power to be generated factoring in line losses. Nuclear plant relicensing and increasing coal power plant emission regulations are already impacting America's generating base. Factoring in economic growth, CHP can provide a significant source of new power generation for the future.

• **Increased Grid Reliability:** On-site power generation has proven to provide improved power reliability by operating when the grid is down. On-site power also provides power quality support for the owner and neighboring sites as well. Electric Power Research Institute (EPRI) reported the first ever power-quality cost estimate of $26 billion per year for the U.S.[15]

• **National Security:** Resource conservation is viewed as a national security issue. The U.S. economy depends on the expectation that energy will be plentiful, available, and affordable. Historically, oil and gas have been used as political and economic weapons by nations to manipulate the marketplace. CHP is among the most efficient means of combusting a fuel to deliver energy.

• **Health Benefits:** Specifically reducing particulate NO_X and SO_2 emissions are important environmental benefits of using CHP systems. Numerous studies concerning these pollutants have determined these are indeed health hazards, and they are regulated as such.

[15] Estimating the cost of power quality. IEEE *Spectrum*. 30(6): 40-41.

1.6 CHP DESIGN BASICS

The following CHP design basics outline provides key insights into a methodological thought process to lead toward site analytics for successful CHP applications.

1.6.1 CHP Design Goals

The fundamental design goal for any CHP system installation is to provide the site owner/operator with an appropriate return on their investment (ROI). Make no mistake, the fundamental reason to install a CHP system is economic. There are influencers, particularly for public sector sites and large multinational corporations, such as efficiency and/or carbon goals, that extend acceptable payback periods and reduce ROI, but economics matter.

A second and equally important design goal is to reduce risk or conversely increase the certainty of results. This can best be accomplished by a thorough understanding of CHP system application considerations, which is the goal of this guide.

1.6.2 General CHP System Configurations and Capabilities

CHP systems consist of three primary components: the unit in which the source fuel is combusted, the electric generator, and the heat recovery unit. CHP systems are differentiated by a "prime mover," the device used to convert fuel (e.g., natural gas, biomass, biogas, coal, waste heat, and oil) into electricity. The most common CHP system configurations use combustion turbine, reciprocating engine, microturbine, or steam turbine prime movers.

A CHP system with a **gas turbine** generates electricity by combusting a fuel (often natural gas, oil or biogas) and using a heat recovery unit to capture the by-product heat. Gas turbine configurations are most compatible with large industrial or commercial CHP applications that require large quantities of heat and power, typically sized between 4 and 50 MW in electric capacity.

A CHP system with a **reciprocating engine** generally recovers heat from the jacket water cooling system and the engine exhaust, providing low pressure steam or hot water under 250°F (121°C). Engine configurations are most compatible with industrial or commercial CHP applications that require quantities of heat and power typically sized between 100 kW and 5 MW in electric capacity.

Microturbine CHP systems are emerging to serve a number of applications with unit sizes between 65 to 250 kW and modular system capacities of 1 MW.

Unlike the gas turbine configuration, which produces heat as a by-product of electricity generation, CHP systems with **steam turbines** generate electricity as a by-product of steam production. Steam turbine configurations are most compatible with industrial facilities where solid fuels (e.g., biomass) feed the boiler.

Finally, **organic Rankine cycle (ORC)** systems, which use an organic working fluid instead of water/steam, are being applied, especially where low-temperature waste heat is available for recovery.

1.6.3 Thermal and Electric Load Requirements

The key driver for CHP economics is operating the CHP system over long hours at high electric and thermal load factors. Simply put, the only way to overcome the capital cost of the CHP system is to operate the system efficiently for as long as possible each year. This typically requires applications with a high degree of coincident electric and thermal loads. Thermal storage can be used to balance coincident electric and thermal loads where it is cost effective.

The most fundamental, and perhaps most difficult, element of a CHP application is understanding a site's thermal and electric loads. In fact, most CHP design failures occur because the systems were incorrectly sized to serve the site's thermal loads. The first step in understanding electric and thermal load is to differentiate between which loads are addressable and which are not. Multiple on-site electric meters generally mean that only one meter set can be considered. This is generally because it is too costly to rewire the facility to be served by a single meter, which would be necessary for the CHP system to provide power to all the loads.

For facilities with rooftop air conditioners, space cooling and likely space heating are not addressable thermal loads, because rooftop air conditioners (not rooftop air handlers) use direct-expansion systems for cooling (versus water coils) and generally use a furnace or heat pump cycle for heating. Even multiple rooftop air-handling units with chilled- and hot-water coils are not likely candidates, because they require extensive piping runs, which generally lead to costly retrofits. Fundamentally, high-thermal-load-factor CHP systems are economical, and low-thermal-load-factor systems are not economically viable. Generally, sizing the CHP system to the addressable thermal load and using the electricity on-site[16] is considered best practice.

A significant portion of this guide is focused on understanding addressable electric and thermal loads.

1.6.4 Power Generation Equipment

Selecting the right prime mover is a function of the site requirements, which drive the capacity of the CHP system to deliver thermal energy and electric power. Energy economics (cost of fuel versus cost of electricity), *N* and *N*+1 considerations (i.e., providing equipment backup), equipment capital cost, installation cost, and permitting play significant roles in prime mover selection. Reciprocating engines, combustion turbines, microturbines, and fuel cells have all been successfully applied.

1.6.5 Electrical Distribution Systems

CHP systems can be designed to operate in parallel with the electric grid, in island mode (separated from the electric grid), or in grid parallel with automatic transfer to island mode when the grid fails. The simplest electric grid interconnection is parallel operation providing no electric power to the grid, because a CHP system generally cannot backfeed electricity to the grid unless permitted by the local utility for specific purposes. CHP generators can provide output at 480 to 13,000 volts.

[16] Current feed-in tariffs for most CHP applications to the electric grid are less than retail electric prices and are often wholesale prices, making exporting electricity uneconomical. Therefore, limiting electricity production to on-site use is current best practice.

1.6.6 Heat Recovery Boilers and Thermally Activated Technologies

The simplest means of heat recovery is the direct use of prime mover exhaust for heating or drying proposes, which often is associated with combustion-turbine- and microturbine-based systems. Far more often, CHP system thermal loads require waste heat be used as hot water, steam, and/or chilled water. Heat recovery steam generators (HRSGs) and heat recovery heat exchangers are used to deliver low- or medium-temperature steam or hot water. The advent of advanced absorption and adsorption chiller technologies further extend CHP system capabilities (at a cost) to satisfy chilled-water and low-temperature refrigeration loads. Thermally activated desiccant dehumidification has also been applied using CHP waste heat streams.

1.6.7 Thermal Distribution System

CHP system designers must understand the type and quality of all addressable thermal loads, determine the tie-in point(s), and obtain the highest degree of thermal load information possible with a minimum of 12 months of data.

1.6.8 Regulations

Electric grid interconnection is the most common regulation connected with CHP systems. However, CHP installations must comply with a host of local zoning, environmental, health, and safety requirements at the site. These include rules on air and water quality, fire prevention, fuel storage, hazardous waste disposal, worker safety, and building construction standards. This requires interaction with various local agencies, including fire districts, air districts, water districts, and planning commissions, many of which may have no previous experience with a CHP project and are unfamiliar with the technologies and systems.

1.7 ENERGY EFFICIENCY

CHP energy efficiency is an important concept to understand and involves knowledge of the CHP system being analyzed and where the energy boundary is drawn. The following sections present the three most common means of measuring overall efficiency: net electric efficiency, overall system efficiency, and electric effectiveness.

1.7.1 Heating Value

Natural gas is often selected as the fuel for CHP systems, although the same considerations discussed here apply to biofuels and other fossil fuels. There are two common ways to define the energy content of fuel: higher heating value and lower heating value.

Turbine, microturbine, engine, and fuel cell manufacturers typically rate their equipment using **lower heating value (LHV)**, which accurately measures combustion efficiency; however, LHV neglects the energy in water vapor formed by combustion of hydrogen in the fuel. This water vapor typically represents about 10% of the energy content. LHVs for natural gas are typically 900 to 950 Btu/ft^3 (33.5 to 35.5 MJ/m^3).

Higher heating value (HHV) for a fuel includes the full energy content as defined by bringing all products of combustion to 77°F (25°C). Natural gas typically is delivered

by the local distribution company with values of 1000 to 1050 Btu/ft^3 (37 to 39 MJ/m^3) on this HHV basis. Because the actual value may vary from month to month, some gas companies convert to therms (1 therm = 100,000 Btu). These measures all represent HHV. Consumers purchase natural gas in terms of its HHV; therefore, performances of CHP systems as well as the electric grid for comparison are calculated in HHV.

The **net electric efficiency** η_E of a generator can be defined by the first law of thermodynamics as net electrical output W_E divided by fuel consumed Q_{fuel} in terms of kilowatt-hours of thermal energy content:

$$\eta_E = W_E/Q_{fuel} \qquad 1\text{-}1$$

A CHP system, by definition, produces useful thermal energy (heat) as well as electricity. If the first law is applied, adding the useful thermal energy Q_{TH} (converted from megajoules to kWh,) to the net electrical output and dividing by the fuel consumed (which is how virtually all CHP system efficiencies are reported), the resulting overall system efficiency η_{CHP} does not account for the relative value of the two different energy streams:

$$\eta_o = (W_E + \Sigma Q_{TH})/Q_{fuel} \qquad 1\text{-}2$$

According to the second law of thermodynamics, the two different energy streams have different relative values; heat and electricity are not interchangeable. The first law describes the quantity of the two energy streams, whereas the second law describes their quality or value (exergy). Electrical energy is generally of higher value because it can do many types of work, and, in theory, 100% of it can be converted into thermal energy. Thermal energy is more limited in use and is converted to work at rates usually much lower than 100% conversion. The theoretical maximum efficiency at which thermal energy can be converted to work is the Carnot efficiency, which is a function of the quality, or temperature, of the thermal energy and is defined as

$$(T_{high} - T_{low})/T_{high} \qquad 1\text{-}3$$

1.7.2 Electric Effectiveness

The current methodology of using net electric efficiency η_E and overall efficiency $\eta_{O,}$ either separately or in combination, does not adequately describe CHP performance because η_E gives no value to thermal output. Overall efficiency η_O is an accurate measure of fuel use but does not differentiate the relative values of the energy outputs and is not directly comparable to any performance metric representing separate power and thermal generation.

CHP electric effectiveness η_{EE} is a single metric that recognizes and adequately values the multiple outputs of CHP systems and allows direct comparison of system performance to the conventional electric grid and competing technologies. This more closely balances the output values of CHP systems and allows CHP system development to be evaluated over time. CHP electric effectiveness views the CHP system as primarily providing thermal energy, with electricity as a by-product. It is then defined as net electrical output divided by incremental fuel consumption of the CHP system above the fuel that would have been required to produce the system's useful thermal output by

conventional means. This approach credits the system's fuel consumption to account for the value of the thermal energy output, and measures how effective the CHP system is at generating power (or mechanical energy) once the thermal needs of a site have been met. This metric is most effective when used on a consistent and standardized basis, meaning:

The η_{EE} metric measures a single point of performance (design point). The design point for power generation is measured at ISO conditions (for combustion turbines, microturbines, and fuel cells, 59 F (15 C), 60% RH, sea level, per ISO Standard 3977-2; for reciprocating engines, 77 °F (25 °C), 30% RH, and 14.5 psia (100 kPa) per ISO Standard 3046-1). The performance evaluates fuel input and CHP outputs at the design point only. HHV is used because it measures the true value of performance in relation to fuel use and fuel cost (HHV is more commonly used to compare energy systems, is the basis of fuel purchases, and is the basis of emissions regulation).

1.7.3 Power and Heating Systems

For CHP systems delivering power and heating (steam and/or hot water, or direct heating), the CHP electric effectiveness is defined as

$$\eta_{EE} = \frac{W_E}{Q_{fuel} - \Sigma\left(\frac{Q_{TH}}{\alpha}\right)} \qquad 1\text{-}4$$

where α is the efficiency of the conventional technology that otherwise would be used to provide the useful thermal energy output of the system (for steam or hot water, a conventional boiler); see Table 1-2.

Examples 1 to 5 demonstrate how to apply this metric. The basis for comparison is a 25% HHV efficient electric power source. Performance values for larger combustion turbines, reciprocating engines, and fuel cells vary significantly.

Example 1. Separate Power and Conventional Thermal Generation. A facility supplies its power and thermal requirements by two separate systems: a conventional boiler for its thermal needs and a power-only generator for electricity.

Conventional Boiler: 100 units of fuel are converted into 80 units of heat and 20 units of exhaust energy as shown in Figure 1-7.

Power-Only Generator: A 25% HHV efficient electric generator consumes 160 units of fuel and produces 40 units of electricity and 120 units of exhaust energy (Figure 1-8).

Table 1-2. Values of α for Conventional Thermal Generation Technologies

Fuel	α
Natural gas boiler	0.80
Biomass boiler	0.65
Direct burner exhaust	1.0

The performance metrics for these separate approaches to energy supply are as follows:

$$\eta_E = \frac{W_E}{Q_{fuel}} = \frac{40}{160} = 0.25 \quad \text{1-5}$$

$$\eta_O = \frac{W_E + \sum Q_{TH}}{Q_{fuel}} = \frac{40 + 80}{160 + 100} = 0.46 \quad \text{1-6}$$

$$\eta_{EE} = \frac{W_E}{Q_{fuel} - \sum\left(\frac{Q_{TH}}{\propto}\right)} = \frac{40}{260 - \left(\frac{80}{0.80}\right)} = 0.25 \quad \text{1-7}$$

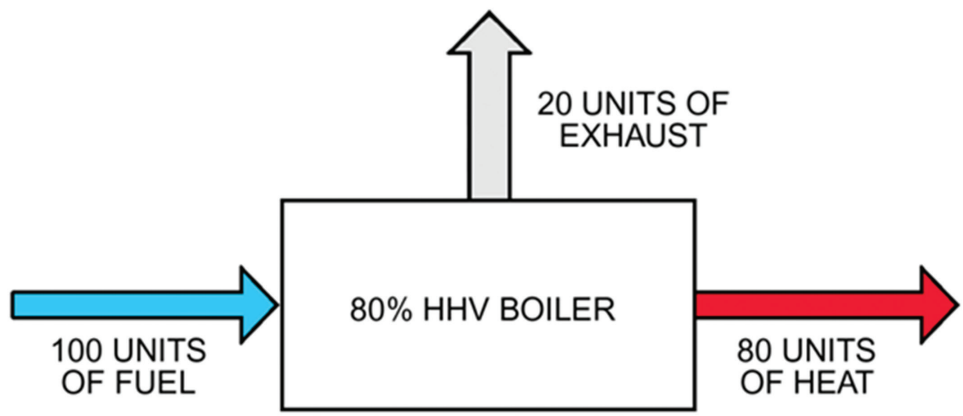


Figure 1-7. *Conventional Boiler for Example 1*

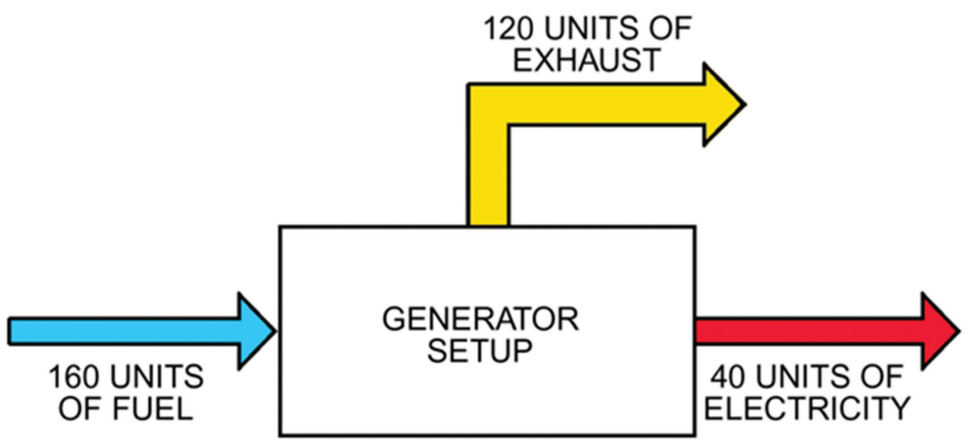


Figure 1-8. *Power-Only Generator for Example 1*

$$\eta_E = \frac{W_E}{Q_{fuel}} = \frac{40}{160} = 0.25 \quad \text{1-8}$$

$$\eta_O = \frac{W_E + \sum Q_{TH}}{Q_{fuel}} = \frac{40+80}{160} = 0.75 \quad \text{1-9}$$

$$\eta_{EE} = \frac{W_E}{Q_{fuel} - \sum\left(\frac{Q_{TH}}{\propto}\right)} = \frac{40}{160 - \left(\frac{80}{0.80}\right)} = 0.67 \quad \text{1-10}$$

Example 2. Combined Power and Thermal Generation (Hot Water/Steam). A CHP system is used to meet the same power and thermal requirements as in Example 1, with a 25% HHV efficient generator and a 67% efficient heat recovery heat exchanger (e.g., a 600°F [315°C] airstream reduced to 240°F [115°C] exhaust and yielding 200°F [93°C] hot water). The performance parameters for this combined system are shown in Figure 1-10.

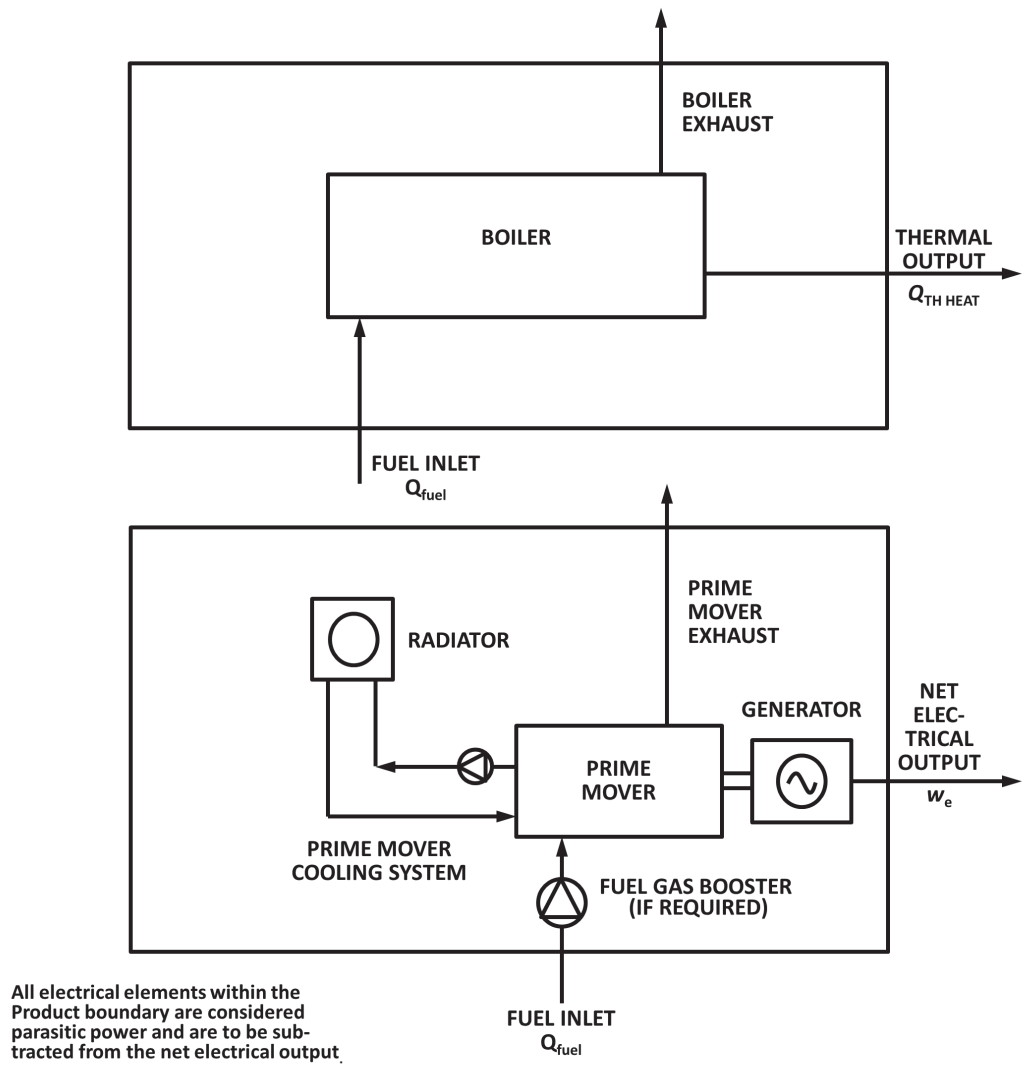


Figure 1-9. *Separate Power and Heating Energy Boundary Diagram for Example 1*

Note that η_E for both systems (Example 1's separate generation and Example 2's CHP) is the same, but the combined system uses less fuel to produce the same outputs, as shown by the differences in overall efficiency (η_O = 75% for CHP versus η_O = 46% for separate systems) (Figure 1-10). However, this metric does not adequately account for the relative values of the thermal and electric outputs. The electric effectiveness metric, on the other hand, nets out the thermal energy, leaving a η_{EE} of 67% for the CHP system versus 25% for separate systems (Figure 1-11).

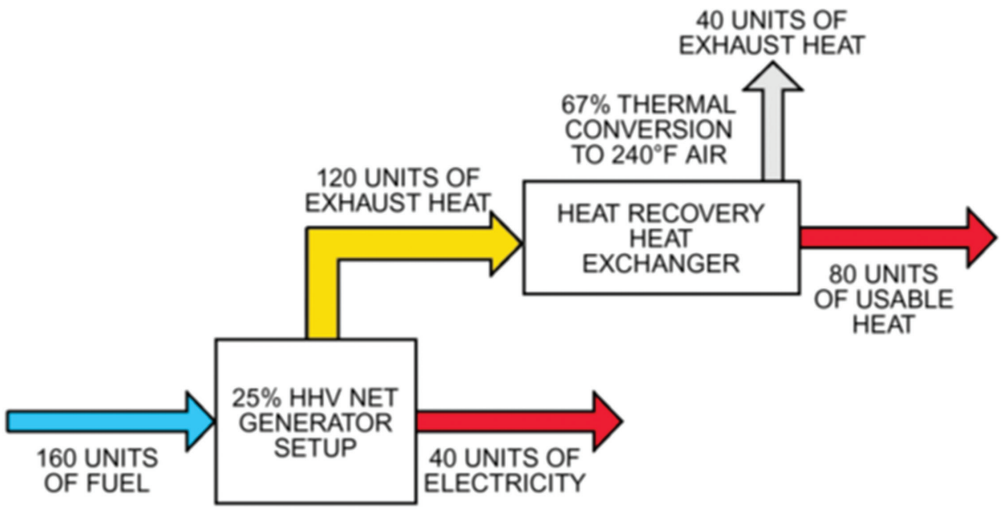


Figure 1-10. *Performance Parameters for Combined System for Example 2*

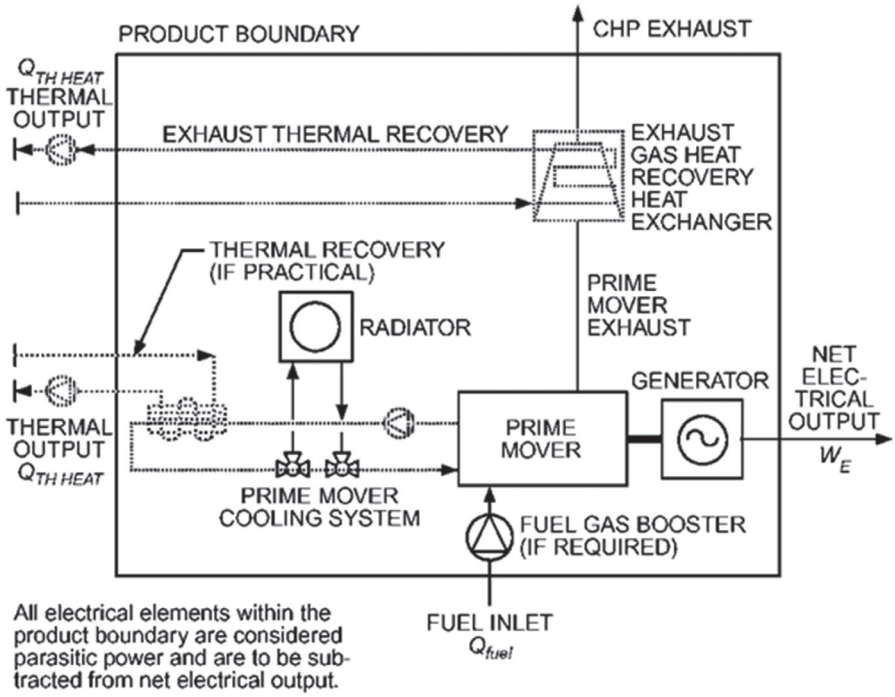


Figure 1-11. *CHP Power and Heating Energy Boundary Diagram for Example 2*

Example 3. Combined Power and Thermal Generation (Direct Exhaust Heat). In some cases, exhaust gases are clean enough to be used for heating directly (e.g., greenhouses and drying where microturbine and gas turbine exhaust is used). For these cases, the thermal recovery efficiency is the difference between exhaust gas temperature and ambient temperature, where delivered exhaust gas temperature is divided by the difference between exhaust gas temperature and outdoor ambient temperature. Direct exhaust gas delivery is a direct-contact form of heating; thus, heat transfer losses are minimal. For a 25% efficient electric generator exhausting into a greenhouse with an internal temperature of 100°F (38°C), thermal recovery efficiency = (600°F – 100°F [315°C – 38°C])/(600°F – 59°F [315°C – 15°C]) = 92% (note that 59°F [15°C] is the ISO rating condition for microturbines per ISO Standard 3977-2).

$$\eta_{\text{thermal recovery}} = \frac{(600\,F - 100\,F\,[315\,C - 38\,C])}{(600\,F - 59\,F\,[315\,C - 15\,C])} \qquad 1\text{-}11$$

$$\eta_{\text{thermal recovery}} = 92\%$$

Performance parameters for this combined system are shown in Figure 1-12, and system boundaries are shown in Figure 1-13.

$$\eta_E = \frac{W_E}{Q_{fuel}} = \frac{40}{160} = 0.25 \qquad 1\text{-}12$$

$$\eta_O = \frac{W_E + \Sigma Q_{TH}}{Q_{fuel}} = \frac{40 + 110}{160} = 0.94 \qquad 1\text{-}13$$

$$\eta_{EE} = \frac{W_E}{Q_{fuel} - \Sigma\left(\frac{Q_{TH}}{\propto}\right)} = \frac{40}{160 - \left(\frac{110}{1.00}\right)} = 0.80 \qquad 1\text{-}14$$

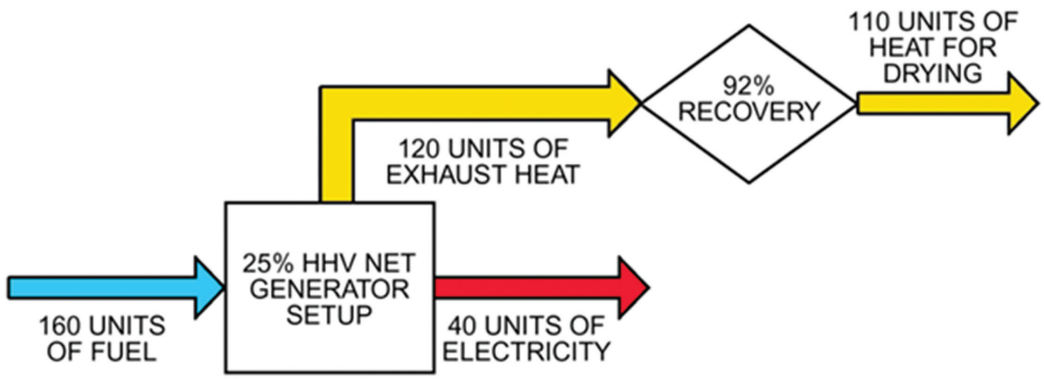


Figure 1-12. *Performance Parameters for Example 3*

$$\eta_E = \frac{W_E}{Q_{fuel}} = \frac{40}{160} = 0.25 \qquad 1\text{-}15$$

$$\eta_O = \frac{W_E + \sum Q_{TH}}{Q_{fuel}} = \frac{40 + 69}{160} = 0.68 \qquad 1\text{-}16$$

$$\eta_{EE} = \frac{W_E}{Q_{fuel} - \sum\left(\frac{Q_{TH}}{\propto}\right)} = \frac{40}{160 - \left(\frac{69}{0.80}\right)} = 0.54 \qquad 1\text{-}17$$

Example 4. Combined Power and Thermal Generation (Combustion Turbine [CT] Without Cofired Duct Burner). In this example, exhaust gas from the 25% efficient electrical combustion turbine generator setup is assessed, first without any exhaust enhancement, and then in Example 5 the same system is assessed with temperature and energy content enhancement using cofiring of additional fuel in a duct burner placed in the exhaust and using a heat recovery steam generator (HRSG). The basis for this example is using fuel input and steam output data from a simple cycle gas turbine, as shown in Figures 1-14 and 1-15.

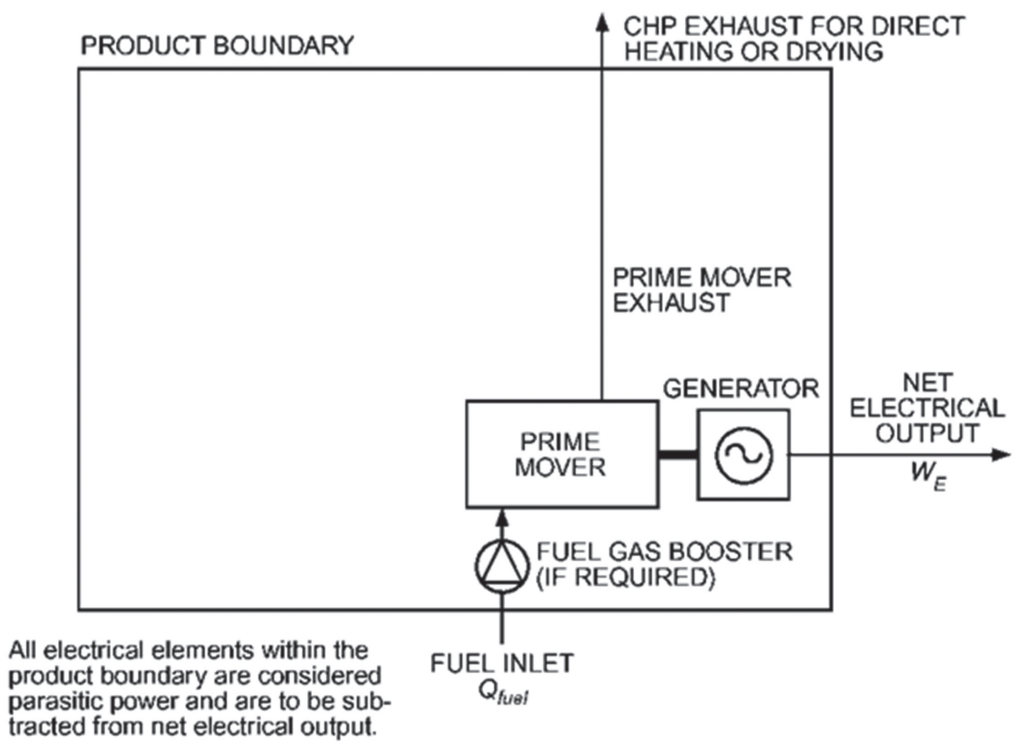


Figure 1-13. *CHP Power and Direct Heating Energy Boundary Diagram for Example 3*