



MILTON MECKLER, P.E., AND LUCAS B. HYMAN, P.E., EDITORS

SUSTAINABLE ON-SITE CHP SYSTEMS

Design, Construction, and Operations

Sustainable On-Site CHP Systems

About the Editors

MILTON MECKLER, P.E., CPC, an ASHRAE, AIC, NAFE, and ASME Fellow, and M. ASCE, is the president of Design Build Systems (DBS), based in Los Angeles, California. As a founding principal and former president of The Meckler Group and Envirodyne Energy Services, he was involved with the design, construction, and management of CHP facilities nationwide. In 2004, Mr. Meckler was selected as one of the four global award finalists for McGraw-Hill's Platts Energy Lifetime Achievement Award. Among the more than 300 MEP design and construction related feature and technical articles, handbooks, and design manuals he authored are *Comparing the Eco-Footprint of On-Site CHP versus EPG Systems* (ASME 2008) and *Designing Sustainable On-Site CHP Systems* (ASHRAE 2007), coauthored by Lucas B. Hyman and Kyle Landis.

LUCAS B. HYMAN, P.E., LEED AP, a professional mechanical engineer with more than 25 years' experience, is a founding member and current president of Goss Engineering, Inc., a firm specializing in the planning and design of district energy systems. The recipient of numerous regional and chapter ASHRAE awards and the author of many published papers and articles, he has been involved in the planning and design of numerous CHP plant facilities. Mr. Hyman's experience includes plant operation and maintenance, developing studies, master plans, and construction documents (design), conducting construction management, and functioning as a commissioning agent.

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Design, Construction, and Operations

Milton Meckler, P.E.

Lucas B. Hyman, P.E.



New York Chicago San Francisco
Lisbon London Madrid Mexico City
Milan New Delhi San Juan
Seoul Singapore Sydney Toronto

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Contributors

Michael A. Anthony, P.E. *Senior Electrical Engineer, University of Michigan, Ann Arbor, Mich.* (CHAP. 23—CASE STUDY 5)

Edward T. Borer, P.E., CEM, LEED AP *Energy Plant Manger, Princeton University, Princeton, N.J.* (CHAP. 19—CASE STUDY 1)

Michael R. Brambley, Ph.D. *Staff Scientist, Pacific Northwest National Laboratory, Richland Wash.* (CHAP. 17)

Gearoid Foley *President, Integrated CHP Systems Corp., Princeton Junction, N.J.* (CHAPS. 4, 6)

Steve Gabel *Principal, Development Engineer, Honeywell ACS Laboratories, Golden Valley, Minn.* (CHAP. 20—CASE STUDY 2)

Jeffrey S. Hankin, P.E., LEED AP *Principal, Sparling, Inc., San Diego, Calif.* (CHAP. 11)

Son H. Ho, Ph. D. *Associate Professor, Department of Mechanical, Materials and Aerospace Engineering, University of Central Florida, Orlando, Fla.* (CHAP. 25—CASE STUDY 7)

Paul Howland, M.B.A. *Executive Director, Maintenance and Operations Facilities Management, University of California, Irvine, Calif.* (CHAP. 16)

Lucas B. Hyman, P.E., LEED AP *President, Goss Engineering, Inc., Corona, Calif.* (CHAPS. 1, 3, 10, 18, 24—CASE STUDY 6)

Srinivas Katipamula, Ph.D. *Staff Scientist, Energy Technology Development, Pacific Northwest National Laboratory, Richland, Wash.* (CHAP. 17)

Kyle Landis, P.E. *Senior Mechanical Engineer, Goss Engineering, Inc., Corona, Calif.* (CHAPS. 9, 10, 24—CASE STUDY 6)

Karl Lany *Principal, SCEC Air Quality Specialists, Orange, Calif.* (CHAPS. 12, 14)

Kelly J. Mamer, P.E., LEED AP *Associate, Electrical Engineering, Sparling, San Diego, Calif.* (CHAP. 11)

Itzhak Maor, Ph.D., P.E., CEM *Manager, Energy Efficiency Services, Johnson Controls, Philadelphia, Pa.* (CHAPS. 2, 8, 9, 21—CASE STUDY 3)

Milton Meckler, P.E., CPC, ASME and ASHRAE Fellow *President, Design Build Systems, Los Angeles, Calif. and Principal, Meckler Forensic Group, Inc., St. Petersburg, Fla.* (CHAPS. 1, 13, 15, 18, 24, 25, 26—CASE STUDIES 6, 7, 8)

Dragos Paraschiv, P.E., Ph.D., M.B.A. *Associate, MCW Custom Energy Solutions Ltd., Toronto, Ont., Canada* (CHAP. 22—CASE STUDY 4)

James Peedin *Vice President, Engineering, LPCiminelli Solutions, Buffalo, N.Y.*
(CHAP. 20—CASE STUDY 2)

Dharam V. Punwani *President, Avalon Consulting, Inc., Naperville, Ill.* (CHAP. 7)

T. Agami Reddy, Ph.D., P.E. *Professor, Department of Civil, Architectural and Environmental Engineering, Drexel University, Philadelphia, Pa.* (CHAPS. 2, 8, 21—CASE STUDY 3)

David C. Rosenberger, LEED AP *Project Manager, Sparling, Inc., San Diego, Calif.* (CHAP. 11)

Thomas J. Rosfjord, Ph.D. *Project Leader (retired), United Technologies Research Center, South Windsor, Conn.* (CHAP. 5)

Adam Stadnik, P.E. *Mechanical Engineer, Goss Engineering, Inc., Corona, Calif.* (CHAP. 3)

Timothy C. Wagner, Ph.D. *Principal Engineer, United Technologies Research Center, East Hartford, Conn.* (CHAP. 5)

Foreword

We are at an interesting juncture in our power and energy generation history. Not only are we to reduce our dependence on foreign sources of fuel and energy sources, but we must also develop inexpensive and indigenous sources of power and energy that are safe, reliable, and environmentally benign. One of the more dependable methods of “stretching” the fuel use of a power or energy source is by utilizing every useful unit of power and thermal energy that can be extracted from a single fuel source and expending any “waste energy” as close to the ambient temperature as possible. This raises not only the efficiency (from a first law of thermodynamics standpoint), but also the effectiveness (from a second law of thermodynamics standpoint) as high as practically feasible. This is where a combined heat and power (CHP) system or a cogeneration system comes into the power and energy realm.

CHP systems are not only more energy efficient but also provide emergency backup to not only the power grid but also to the “thermal network” of a industrial plant, central plant, building, or a building complex. The thermodynamic efficiency of CHP systems has been measured at 65 to 80 percent, depending on the prime mover (engine or turbine), the quality of the exhaust stream (temperature and pressure and hence the enthalpy) and the effectiveness of the heat recovery steam generator (HRSG) that produces the useful thermal stream for use in the thermal network of a building. This means that a typical CHP system is quite complex in its operation and maintenance scheme. This demands expert training of the operator(s) in not only keeping the system operational at regular times but also in anticipating problems and being able to troubleshoot and prevent any system breakdowns before they occur.

The book has been organized in six major sections (parts) focused on the planning, design, construction, and operation of CHP. Part 1 outlines the basics of CHP systems and regulations; Part 2 discusses how to complete a feasibility study and a life-cycle-cost analysis; Part 3 focuses on design and how to develop a CHP plant from scratch and deal with risk management issues, which are critical to its economic success; Part 4 provides guidelines for the construction process including operations; and Part 5 discusses plant operations and continued maintenance. The book also includes (Part 6) a wide variety of selected CHP case studies from leaders, contributors, and experts in the field. CHP also provides opportunities for businesses to become carbon neutral by using biofuels to power their CHP systems.

This book has included discussion issues believed to be relevant for mechanical and electrical engineers, building owners, developers, building and plant operators, architects, and contractors involved with the design and management of building and

industrial heating, cooling and power needs in the twenty-first century. As energy use and energy costs continue to rise, one must look to CHP opportunities for increasing building, industrial, and manufacturing energy-use efficiencies in minimizing use of purchased prime energy by displacing it with useful energy and/or power obtained by harnessing available waste heat sources more effectively.

Finally, this book also offers numerous useful suggestions for those charged with providing sustainable operation of the CHP system. Being able to conduct system diagnostics and expert control of these CHP systems in a cost-effective manner not only delivers power, cooling and heat in a reliable manner, but also does it with a minimal environmental footprint.

CHP systems often also form the backbone of a distributed energy (DE) resource, which can be tapped into the power grid either individually or in aggregated multi-kilowatt blocks. As my PNNL colleague (Don Hammerstrom) noted in a recent article by David Engle titled "The Grid Wise Future," DE resources can have an expanded role in the future scenario of a completely revamped electrical grid system, often called the "smart grid," especially for backup generators including standby emergency power systems. So, looking into the future, the CHP systems probably offer even a wider array of applications than have been envisioned thus far.

DR. SRIRAM SOMASUNDARAM, FASME, FASHRAE
Pacific Northwest National Laboratory, Richland, Washington

Preface

This book was written to share our collective knowledge regarding this important technology that literally has been around for centuries. Modern combined heat and power, or CHP, is a proven mature technology that still benefits from advances in modern science. A technology that is sustainable, and as will be seen, offers important advantages to reducing total CO₂ emissions. Therefore, this book offers a guide to the issues one needs to familiarize themselves with when planning, designing, constructing, or operating a sustainable on-site CHP facility and is divided into six parts:

- Part 1—CHP Basics
- Part 2—The Feasibility Study
- Part 3—Design
- Part 4—Construction
- Part 5—Operations
- Part 6—Case Studies

Part 1, CHP Basics, provides an overview, key definitions and concepts, a discussion of power equipment and thermal recovery use options, packaged CHP systems, key regulatory issues and challenges, emission impacts and mitigating control options, the applicability of CHP systems, and an overview of utility price signals. A study of Part 1 will provide the reader with a good understanding of what CHP is, how CHP can make a difference in working towards a sustainable future, the choices available when selecting power equipment, the choices available for heat recovery and beneficial thermal use, regulatory issues to consider, the emission control options available, and an overview of CHP applicability.

Part 2, The Feasibility Study, reviews fundamental concepts that are necessary to plan properly a sustainable CHP plant, to conduct a life-cycle-cost (LCC) analysis, and to provide for system optimizing. The feasibility study is the point at which key issues and alternatives are investigated, and plans are optimized. The completed approved study provides a road map that engineers will follow during the design effort [e.g., designing a 1500-kW reciprocating engine generator CHP system with hot water-fired absorption chillers versus designing a 2-MW combustion turbine generator (CTG) with a steam heat recovery steam generator (HRSG)].

Part 3, Design, discusses some of the key engineering issues including electrical interconnection design issues, as well as what is needed to have plans approved and to obtain a Permit to Construct (i.e., authorization to begin construction). Part 4, Construction, discusses construction issues including different contractual organization structures and contract delivery methods as well as risk assessment. Part 5, Operations, discusses requirements to keep a CHP plant sustainable, operating as intended, as well as most importantly how to monitor and obtain performance improvements for continued sustainability. Part 6, Case Studies, provides a number of case studies to provide examples of how sustainable on-site CHP systems are planned, designed, constructed, and operated in an efficient and sustainable manner.

A glossary of terms is provided.

The authors wish to sincerely thank the numerous contributors who volunteered many hours preparing their chapter or case study. It is the authors' sincere hope that readers will be able to learn from the information contained in this book and apply CHP in practice to help make a more sustainable world.

MILTON MECKLER, P.E.

LUCAS B. HYMAN, P.E.

CHP Basics

CHAPTER 1

Overview

CHAPTER 2

Applicability of CHP Systems

CHAPTER 3

Power Equipment and Systems

CHAPTER 4

Thermal Design for CHP

CHAPTER 5

Packaged CHP Systems

CHAPTER 6

Regulatory Issues

CHAPTER 7

Carbon Footprint—Environmental
Benefits and Emission Controls

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CHAPTER 1

Overview

Lucas B. Hyman

Milton Meckler

Combined heat and power (CHP), also known as *cogeneration* as well as several other names, is the simultaneous production of heat and the generation of power (typically electric power) from a single fuel source and which, as will be seen, also builds on the convergence and integration of most state-of-the-art engineering disciplines. On-site CHP is a time-tested, proven technology that offers many important benefits to building and facility owners and operators, to local and regional utility systems, to a country's economic competitiveness and security, and to human society as a whole. Sustainable on-site CHP's important benefits include

- Increased total system thermodynamic efficiency.
- Lowered overall facility energy consumption costs.
- Improved overall facility reliability.
- Reduced electricity demand on constrained utility grid and fully loaded generation equipment.
- Reduced source energy use (i.e., total fuel consumption).
- Reduced total CO₂ emissions, which have been linked to global warming.
- Ability to use biofuels, which are sustainable and essentially carbon neutral.

As discussed in Chap. 2, CHP can benefit a variety of facilities and multiple tens of thousands of megawatts (MW) of CHP capacity have been installed throughout the industrialized world in a wide variety of facilities including

- District energy systems
- Universities and colleges
- Hospitals
- Municipal centers
- Commercial campuses
- Large commercial buildings

- Data centers
- Jails and prisons
- Oil refineries
- Wastewater treatment plants
- Pharmaceutical industries
- Industries requiring heating processes
- Residential systems

The necessary key condition for a sustainable on-site CHP system, in addition to a need for power, is a simultaneous need for heating and/or heat-produced cooling and/or other thermally activated technologies, although thermal storage can offer a way of shifting when loads are served. CHP is primarily driven by several factors, but two major drivers are (1) the return on investment (ROI) and (2) the perceived concern about outages affecting reliability and/or profitability. Main reasons motivating end users to consider CHP also include price, availability of electricity, and capital funding constraints. CHP systems are usually most economical when an existing facility distribution infrastructure system exists, or when CHP systems are installed as part of new facilities, or when utility electricity distribution systems are constrained, and/or when electric utility purchase costs versus fuel costs are relatively high.

Typical fuel sources today include natural gas and fuel oils; however, other common more sustainable fuels include biomass, biofuels (liquids such as ethanol and biodiesel), gas, landfill gas, and municipal waste. CHP offers a proven method to reduce CO₂ emissions by recovering useful heat and avoiding fuel combustion.

Most CHP plants are interconnected with the local utility and operate in parallel. In some cases, the CHP plant may be able to operate totally separated from utility power and is known as *island mode*.

When properly planned, designed, constructed, and operated, sustainable on-site CHP systems offer a proven method (1) to lower overall facility energy consumption and costs, and (2) to reduce total overall utility system fuel consumption. Additionally, there is a need to rethink current and future requirements for expanding electric power infrastructures to meet demands in an era of growing energy uncertainties. This is especially true in areas with old, constrained electrical infrastructures; CHP offers an opportunity to effect reduced reliance on prime energy sources for power generation (utility) and to reduce power transmission system strains.

Sustainable CHP at a minimum is a plant that is cost-effective on a life-cycle cost basis versus conventional remote power generation, and capable of at least a projected annual 70 percent prime energy utilization factor. The use of biofuels (solid, liquid, or gas) can further enhance CHP sustainability as carbon is resequenced during the growing process. Recognize that global warming concerns demand that alternative means to satisfy the world's growing population and power need to be sought while simultaneously curtailing annual carbon dioxide emissions. This remains the foreseeable challenge and CHP is part of both short- and long-term sustainable solutions.

Why CHP?

CHP systems can use less than 60 percent of the source fuel required by conventional utility power plant systems and local facility heating boilers. In a conventional electric power generation plant, the combustion of fuel provides the energy to produce electric

power. Generally, this power production process takes one of two forms. The first form involves the combustion of fuel in boilers to produce steam. The steam is then used to drive steam turbines that are connected to electric generators. The steam exhausted from the turbines is condensed (heat is rejected to the atmosphere) and condensate is sent to the boiler to restart the cycle. The second form of power production involves the combustion of fuel in internal combustion reciprocating engines or combustion turbines that are connected to electric generators.

Both these processes have one major similarity; in each case a majority of the energy available from fuel ends up as waste heat rather than being converted to useful energy or work. In a typical conventional utility power plant, only slightly more than one-third of the energy in the fuel is converted to net electric power. By contrast, in a CHP facility, in addition to the power production, at least half of the exhaust heat, as well as heat from engine-cooling water and other sources as applicable, is recovered and used beneficially at the facility for meeting heat requirements. Figure 1-1 provides a graphical comparison of net energy provided in the form of heat and power versus source fuel input for both a conventional systems and a CHP system.

Specifically, conventional power generation using fossil fuel sources still remains in the range of 35 to 40 percent efficiency when producing electric power at the remote utility plant site. Overall system efficiency is further diminished due to approximate 10 percent or more power transmission losses, which equates to an approximate 6 percent loss of source energy from the utility power plant to the point of use in buildings or industries. The use of sustainable on-site CHP systems versus conventional remote electric power plants and local fuel-fired boilers can result in reducing the energy loss

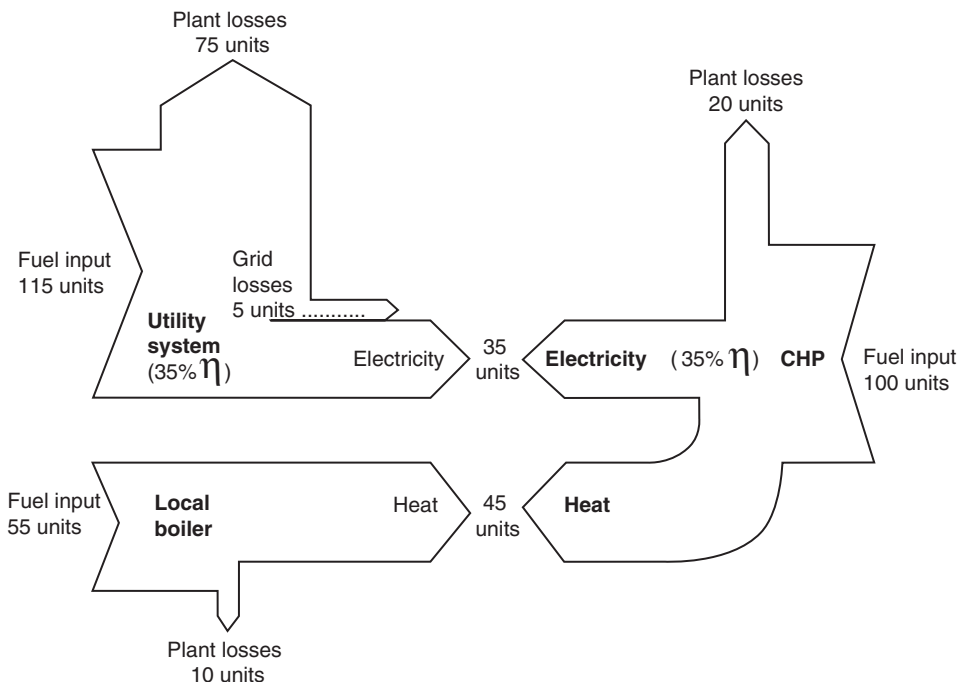


FIGURE 1-1 Conventional utility power generation and local boiler heat versus CHP.

burden per delivered on-site kilowatt of electricity by a factor of approximately 2 to 3. Furthermore, by utilizing on-site power generation (versus a remote utility) the facility can benefit from waste-heat-powered simultaneous cooling and heating, further reducing net facility electric power demands. Additionally, reducing associated demands of fossil fuel for electric power generation by only 15 percent along with an overall reduction in net carbon dioxide emission rate would increase above referenced CHP benefit to a factor of 2.6 to 3.3. And these results can occur without further investment in transmission infrastructure needed to eliminate current electric power grid bottlenecks during periods of high daily peak demand.

History

The rise of engineering in a professional sense had its origins in the eighteenth century as it became principally applied to fields in which mathematics and science converged to permit methods and machines to evolve more rapidly from innovative ideas to practical applications involving mechanical means that could substitute for animal- and human-labor-powered devices in a more efficient and cost-effective manner.

Similarly the pursuits of earlier military and civil engineers whose unique skills and personal insights honed from ancient mathematics became applied to the construction of massive structures, ingenious mechanisms, and military machines. In the mid- to late-nineteenth-century improvements in vehicle design by such innovators as Diesel and Westinghouse merged with earlier mid- to late-eighteenth century newly found energy sources introduced by Savery, Watt, and others giving rise to the development of specialized machines and tools which formed the basis for mechanical engineering.

With the advent of electricity, electronics, chemistry, and physics evolving independently from the experimental findings of Franklin, Faraday, Maxwell, Olm, Hertz, Seeback, Peltier, and others led to electrical engineering being founded. Industrial-scale manufacturing demanded new materials and new processes developed in the late-nineteenth century and led to the need for large-scale production of chemicals from which a new industry was created dedicated to the development and large-scale manufacturing of chemicals in new industrial plants, laying the foundation for chemical engineering which also evolved from the mid- to late-nineteenth century and accelerated into the early- to mid-twentieth century.

The timely convergence of engineering disciplines within the above time period gave rise to the Industrial Revolution which first emerged in England and rapidly spread from there to Europe and America, ultimately leading to diverse modern era engineering professions which continue to evolve and bifurcate at a more rapid pace today in response to growing human industrial and health needs, and perceived global challenges with uncertain outcomes.

All of these disciplines are evident in the use of combined heat and power. The first recorded use of combining heat and power can be traced back to the smokejack, which was introduced to Europe in the fourteenth century.¹ The smokejack was an apparatus which turned a fireplace roasting spit, getting its power from a turbine wheel which was set in motion (i.e., rotated) by the hot flue gas rising in the chimney. The smokejack was essentially the first hot-air turbine-powered equipment, and was the forefather of propellers and gas turbines. By the early 1600s, engineers had figured out that they could get the smokejacks to rotate even without a fire burning by injecting steam from boilers into the exhaust stack, and engineers were busy experimenting with steam-driven

turbines or “steam jacks.” In the 1630s, projects were reported that used a *single fire* to produce mechanical power, process heat, and heat for space heating. The first steam jack was patented by John Bailey of New York City in 1792.

In the late 1700s, engineers and scientist, including James Watt, were working on real-world challenges for factories and agriculture mills on how to produce both heat and power from a single fire (i.e., CHP). Watt’s company advertised their services to provide mechanical power from steam engines as well as to provide simultaneously steam or hot water heating. Through the early 1800s, many engineers and scientist worked on improving steam engines using the exhaust heat as well as the steam itself (which was typically exhausted to atmosphere) to provide heating. Some facilities employed *bottoming-cycles* when the facility was primarily interested in heat for their process, while other facilities employed *topping-cycles* when the facility was primarily interested in mechanical power for their factories and wanted to use the waste heat for heating so that they did not have to purchase and burn firewood separately.

In the early 1800s, Oliver Evans received several high-pressure steam engine patents and advertised high-pressure steam engines that could save a facility money by also simultaneously providing for process heating. Evans marketed CHP systems with some success, and the Columbian Steam Engine business was carried on by his son and business partner. At the same time, CHP systems were also used in English factories and were beginning to be used in other applications, and throughout the 1800s scientist and engineers continued to make advancements with steam engines, their applications, and the simultaneous development of mechanical power and useful thermal energy. Many modern buildings by the late 1800s used steam engines to operate pumps, elevators, and other machinery, and virtually all of those buildings used the exhaust steam for space heating. At the beginning of the twentieth century, CHP was a common accepted practice in many parts of the industrialized world.

The first electric power generating plants became operational in the 1880s and most were cogeneration facilities supplying steam heating to the local neighborhood. Some in those communities served felt that the utility companies had an unfair advantage being allowed to provide CHP. And, over time, small facility CHP systems found it difficult to compete economically with the large CHP utility companies such as New York Edison, which due to economies of scale could sell its electric power and steam more cheaply than could be generated locally.

Around the world, especially in Europe and Russia, engineers continued to improve and expand the use of cogeneration. In 1914, German engineers were recovering heat from internal combustion engines to warm factories (and of course applied that technology to cars a decade later). In fact, German and Russian engineers and policy makers recognized the competitive advantage CHP would provide to their economies by minimizing fuel consumption costs, and government agencies were formed to explore the most efficient CHP technologies and develop industrial policies.

Many professional engineering organizations devoted some of their resources to CHP systems including the American Society of Heating and Ventilating Engineers (ASHVE), the forerunner to the present day American Society of Heating, Refrigeration, and Air-Conditioning Engineers (ASHRAE). The first World Power Congress was held in London in 1924, where waste heat utilization was a topic of discussion. A full session was devoted to CHP at the second congress in Berlin in 1932.

In the early 1920s, in the United States utility CHP systems began to decline as the national electric grid was developed and utility power plants were located close to fuel

sources (typically coal at that time) to minimize fuel transportation costs, but away from customers who could benefit from the waste heat. Many engineers, including Evan's grandson, wrote papers showing how CHP consumed much less fuel compared against even the most efficient condensing steam power plant, but to little avail.

While CHP declined in the United States in the mid-twentieth century, there were exceptions, both with utility plants that provided heat to adjacent facilities, and facility CHP systems that used the heat internally. An important milestone in CHP development was the commercialization of combustion turbine generators (an air compressor coupled to a gas turbine coupled to an electric generator with fuel injected into the combustion chamber, see Chap. 3) in the late 1930s, and several methods were developed to use the waste heat, including heat recovery steam generators (HRSG). Note that combustion turbine generators (CTG) are often called gas turbines, which technically are just a portion of the CTG.

In the 1960s, interest in CHP systems began slowly to reemerge in the United States, and the first CTG CHP plant was installed to provide power, heating, and cooling to the Park Plaza Shopping Center in Little Rock, Arkansas. However, even though engineers showed interest and knew the value of CHP systems, one report stated that CHP systems accounted for 15 percent of total U.S. power production in 1950, but only for 5 percent by the mid-1970s.

For those customers who wanted to install their own CHP systems, utility companies, not unexpectedly, resisted the loss of kilowatthour (kWh) sales and did not want to interconnect with those facilities that installed their own CHP system. In 1978, in the United States, due in part to the energy crisis being experienced by world industrial economies at the time, and in the interest of improving energy efficiency, the U.S. Congress as part of the National Energy Act passed the Public Utility Regulatory Policies Act (PURPA). The law provided for a nonutility power market and mandated that utility companies purchase electric power from CHP facilities which met the minimum efficiency requirements. PURPA is regulated by the U.S. Federal Energy Regulatory Commission (FERC).

Today, as energy prices remain volatile and the consequences of global warming loom, there is a renewed appreciation and interest in CHP systems for the reasons highlighted earlier, including the prospect of lower energy costs, improved reliability, lower prime fuel usage, and helping to limit global warming by reducing overall carbon emissions.

CHP Basics

CHP systems use a variety of prime movers [e.g., reciprocating engines (CTGs)] to generate power. Further, CHP systems, importantly, recover useful thermal energy from engines and/or exhaust gas for beneficial use in facilities and industries for space heating, space cooling, domestic hot water production, dehumidification, and even for additional power production (*combined cycle*) as shown in Fig. 1-2.² Efficient, sustainable CHP systems maximize all available opportunities to utilize fuel energy that the prime mover is unable to convert into shaft energy. If waste heat cannot be utilized effectively, the resulting CHP plant efficiency, in effect, defaults to the limit of the prime mover efficiency. Smaller prime movers cannot match the comparable performance of utility-size prime movers. Where facility thermal energy requirements can utilize the waste heat available from the prime mover, on-site equipment and energy requirements are reduced and overall plant efficiency is increased.

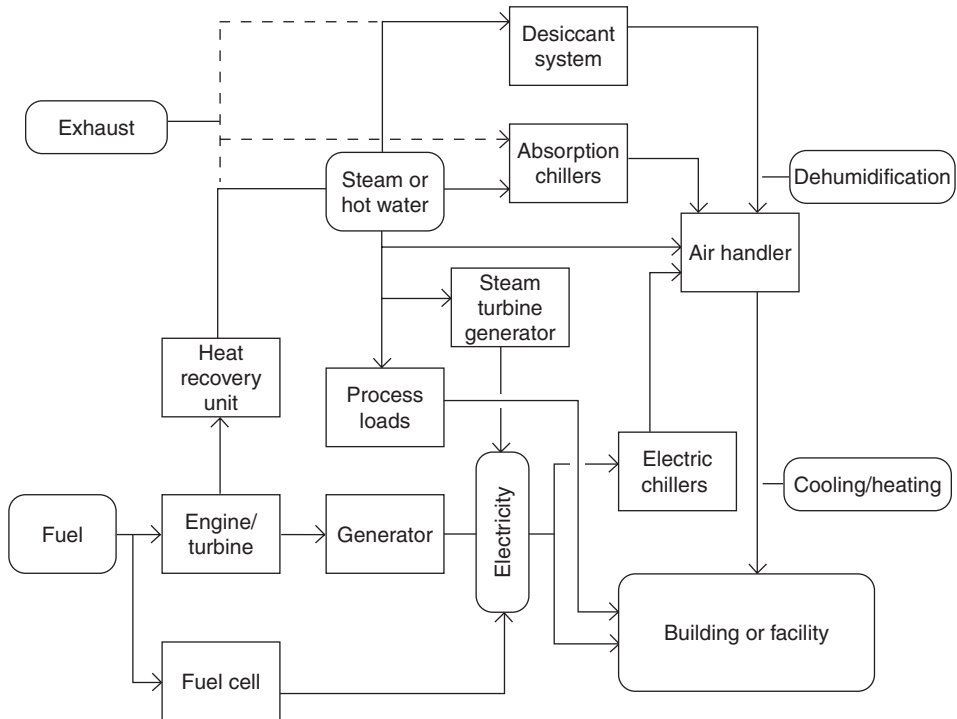


FIGURE 1-2 CHP facility schematic diagram (dashed lines represent an alternate direct fired option).

CHP feasibility and design depend on the magnitude, duration, and coincidence of electrical and thermal loads, as well as on the selection of the prime mover and waste heat recovery systems employed. Integrating the design of the project's electrical and thermal energy requirements with a proposed CHP plant, as well as the proper selection and matching of the prime mover by size and type with system components that recover waste heat, are the key requirements for a successful, sustainable CHP system. In addition, proposed facility location, distance from existing or new load centers, the need for backup to ensure reliability, staff capability and training, and prior CHP plant design and operating experience, all are among the technical issues requiring careful consideration. In general, the more efficient the CHP plant, the better are the overall economics. It is possible to obtain 80 percent and greater overall power plant efficiency in both large and small cogeneration systems by proper matching of equipment and thermal/power demand.

When cooling is also generated by waste heat in a CHP plant, a process known as *trigeneration* (three products from one fuel source) or as combined cooling, heating, and power (CCHP), the result can be higher waste heat utilization and a faster investment payback than comparable cogeneration approaches. Incremental costs can range from simply employing a single-stage absorption chiller for low-temperature waste-heat-driven cooling to more sophisticated integrated hybrid cycles for even greater efficiencies and economics. The decision as to which plant approach provides the owner

with the best return on investment (ROI) and/or outcome typically requires a critical analysis of probable operating scenarios, which rely heavily upon historical operating information along with facility current and foreseeable needs.

Use of CHP is generally more attractive within larger buildings with multiple use occupancies and/or longer daily operating hours and particularly in urban areas where high electrical and somewhat lower gas rates prevail. CHP is also more common where utilization of available waste heat for cooling production can minimize peak electrical demand by offsetting electric-drive chiller operation.

Where greater availability and selection among low-cost microturbines exist, interest in both co- and trigeneration is increasing. Additionally, where opportunities for larger combined (i.e., hybrid) operations exist, both co- and trigeneration are provided with further incentives. Such opportunities have created greater owner interest. Yet until recently, CHP applications were often overlooked by facility owners. Of course, challenges sometimes arise with noise reduction, available gas pressure at the site, particularly for CTGs, and lack of staff experience. Combined gas and electrical utilities tend to be more flexible, particularly when CHP facilities are intended to operate in parallel with the serving utility. Sometimes, excessive utility interconnect requirements or owner disappointment with income streams can serve as a barrier to CHP implementation.

Figure 1-3 shows a simplified schematic diagram of typical basic CHP system. The key components of most CHP systems are the

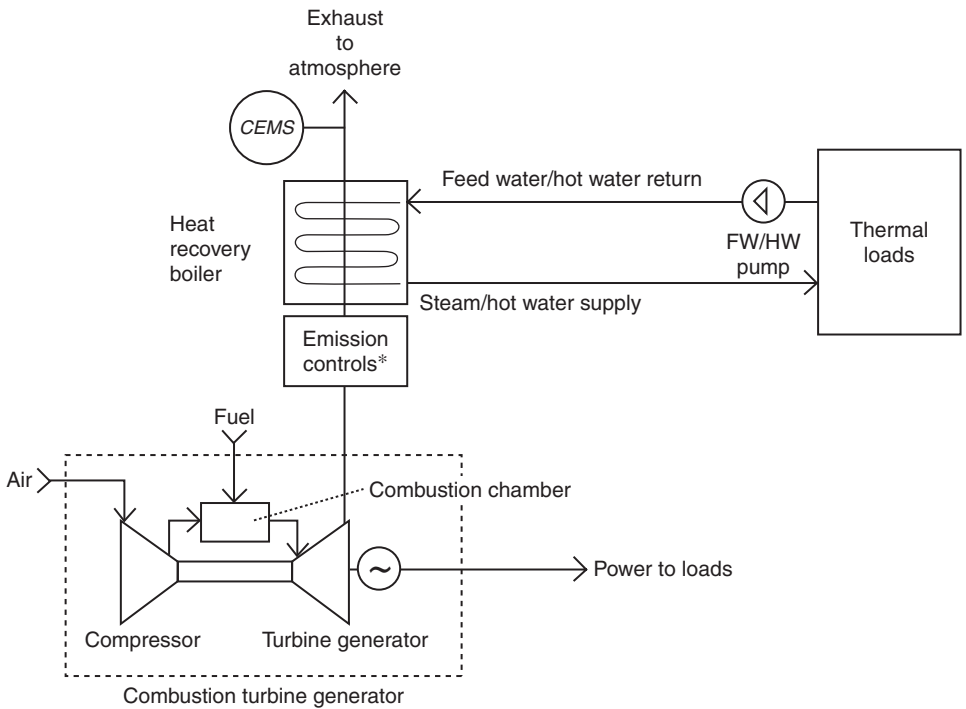


FIGURE 1-3 Typical basic CHP system schematic diagram. *Location in exhaust stream depends on required temperatures.

- Engine(s) or prime mover(s)
- Generator(s) and electrical paralleling/distribution system
- Heat recovery boiler(s) (e.g., HRSG and HRHWG—heat recovery hot water generator)
- Thermally activated components and/or facility thermal uses
- Emission control system

The following paragraphs provide some basics on CHP components. Additional details on prime movers can be found in Chap. 3 and on heat recovery devices and thermal technologies in Chap. 4.

Engine Types

There are a variety of engine types and sizes which can be used as the prime mover for electric power generation. Prime mover choices include internal combustion (IC) reciprocating engines, combustion turbine generators, microturbines, and fuel cells (which is not really a prime mover per se). The following paragraphs provide a brief description of the different CHP engines.

Internal Combustion Reciprocating Engines

As shown in Chap. 2, IC engines (both spark ignition and compression ignition) are the principal prime movers used in smaller (typically less than 1 MW) CHP plants. Most people are familiar with the IC engine as one powers their automobile; key components include the pistons and rods, heads, valves, crankshaft, and engine block. Reciprocating IC engines are available in a wide range of sizes from 50 kW to more than 5 MW and are able to use all types of liquid and gaseous fuels, including methane from landfills or sewage treatment plant digesters. Reciprocating engines are classified as either *rich-burn engines* or *lean-burn engines* depending on the fuel-air ratio. Internal combustion engines that use the diesel cycle (compression ignition) can be fueled by a wide range of fuel oils, and today there is a move to use biodiesel in place of petroleum diesel which improves the CHP plant eco-footprint.

Waste heat, in the form of hot water or low-pressure steam (maximum of 30 psig but typically 15 psig or less), can be recovered from the IC engine jacket manifolds, the lubrication system, and the flue exhaust.

Combustion Turbine Generators

CTG are typically used in larger facilities with electric loads larger than 1 MW. A combustion turbine is similar to a jet engine; the key components include the compressor, combustor, and turbine. CTG are commercially available in sizes ranging from approximately 1 MW to more than 100 MW for utility power plants. CTG are also able to operate on a wide variety of fuels, although some fuel treatment may be required.

For combustion turbine cycle engines, average fuel to electrical shaft efficiencies generally range from less than 20 percent to more than 35 percent. The remainder of the fuel energy is discharged in the exhaust, with some loss through radiation or internal coolants in large combustion turbine generators, and the exhaust heat is recovered in a HRSG. Because combustion turbine exhaust contains a large percentage of excess air, duct burners may be installed in the exhaust for supplementary firing to generate additional steam. Duct burners can be very efficient, exceeding 90 percent.

Microturbines

Microturbines are essentially miniaturized combustion turbine generators and are presently available in sizes up to approximately 250 kW. Microturbines can be ganged together to provide greater capacity and some systems have been designed with more than 1 MW of capacity.

Fuel Cells

Fuel cells are becoming more popular due to their high efficiency and low emissions; however, price hurdles, as compared to other CHP technologies, remain. Engine or combustion turbine-based CHP systems rely on the combustion of fuel to provide the mechanical and thermal energy. In fuel cells, the process takes place as a chemical reaction rather than as combustion. A fuel cell is an electrochemical device that converts hydrogen to DC electricity, with heat and water as by-products. There are different types of fuel cells such as phosphoric acid (PA), proton-exchange membrane (PEM), and molten carbonate (MC). The type of fuel cell determines the electrolyte used to separate the hydrogen ions. Fuel cells are similar to batteries, except that in batteries the chemical reaction that produces the electric power consumes the battery internals. As a result, batteries, even the rechargeable type, eventually wear out. Fuel cells on the other hand use a continuous supply of fuel for the chemical reaction, and provided the fuel supply continues, can operate for extended periods. Although many variations exist, the most common type of fuel cell uses hydrogen as the fuel source and the oxygen in air to complete the chemical reaction. The source of the hydrogen is typically natural gas (which is cracked to release the hydrogen) and the by-product of the chemical reaction is hot water.

The advantages of fuel cells are that they are practically emission free, they operate at very low noise levels, and they are able to respond rapidly to changes in electrical loads. Heat recovery allows the fuel cells to reach an energy conversion efficiency of 80 percent or more. Fuel cells are potential candidates for CHP because the water by-product is produced at temperatures in the 160 to 180°F range (PEM), which is suitable for space heating and other low-temperature uses (e.g., domestic hot water generation and swimming pool heating).

Heat Rate

The heat rate is the ratio of fuel input in British thermal units (Btu) to electric power output in kilowatts (kW), and is a measure of the CTG's (or engine's) fuel-to-electric-power conversion efficiency. The lower the heat rate, the more efficient the CTG or engine. That is, prime movers with lower heat rates deliver the same amount of power than those with higher heat rates with less fuel combustion.

Published heat rates and power outputs are nominal values only. For example, the entering air temperature dramatically affects both the heat rate, and the power output of a given CTG. Output power decreases and the heat rate increases (i.e., efficiency decreases) with increasing combustion inlet air temperature. The CTG nominal values are typically based on an inlet air temperature of 59°F. The inlet air can be cooled on hot days with evaporative cooling or chilled water in a water-to-air heat exchanger, for example, to maintain at least the nominal heat rate and power output values.

In addition to the heat rate, it is important to look at the overall system efficiency. As shown in Chap. 17, the total system efficiency is equal to the sum of the power output plus the thermal energy output divided by the total fuel input in consistent units. It is possible to have a low heat rate (i.e., high electric power generation efficiency) but have

a low overall plant system efficiency due to insufficient thermal energy use, as well as it is possible to have a low electric power generation efficiency but have a high overall plant system efficiency due to maximum heat recovery and thermal energy use.

Generators and Electrical Distribution Systems

The generator and electrical distribution system are key components of a CHP system and there are numerous electrical issues and challenges that must be understood in order to properly plan, design, construct, and operate a successful, sustainable CHP system. The type of CHP system has an effect on the generator type, its design characters, and protections required. The generator, which must be grounded, supplies power to the switchgear, which feeds the CHP plant and facilities. As discussed in Chap. 11 of this book, there are a variety of utility interconnection rules, standards, and requirements to help ensure that the generator and electrical system are protected in case of system power outages, shorts, and other malfunctions such as electrical system voltage spikes and sags. There are also a number of generator types and configurations and these are also discussed further in Chap. 11.

Heat Recovery Boilers

A heat recovery boiler is similar to a typical fuel-fired boiler, except that instead of having a combustion chamber or firebox, the unfired pressure vessel extracts heat from the prime mover exhaust to produce either hot water or steam. Maximum steam pressure is a function of the flue exhaust gas temperature. As previously noted, a heat recovery boiler that produces steam is known as a *heat recovery steam generator* (HRSG).

Alternative Use of Heat Transfer Fluids

A non-volatile fluid-based heat recovery system incorporating a hybrid heater has been proposed as an improvement on HRSG.³ This approach utilizes oil designed for use as a heat transfer fluid which has very good resistance to overheating. In particular, the oil can be heated up to 600°F, and, if overheated, it creates small particles of burned oil which stay in solution rather than coating the walls of a heat exchanger. The oil is used to transfer heat from the combustion turbine exhaust stream to a hybrid heater used for steam generation. Claimed advantages of the oil-based system are as follows:

- Much smaller thermal mass of oil and water in the system as compared with a HRSG, thus allowing much quicker response to varying thermal input.
- Low-pressure operation of the oil loop, which reduces the mechanical requirements of the exhaust heat exchanger, making it more robust to thermal cycling.
- Relaxed mechanical requirements for the exhaust heat exchanger and removing the steam generated from exhaust stream allows for more compact heat exchanger design.
- Reduced exhaust heat exchanger pressure drop, which results in slight improvement in power generation.
- Lower overall installation cost.

When used for steam generation, the hot oil approach may result in reduced total heat recovery due to pinch point issues. However, the hot oil could also be used directly

for equipment in which its temperature glide can be matched better, such as a heating system or an absorption chiller. Use of hot oil could be a better approach than use of steam, hot water, or direct exhaust firing of absorption chillers in CHP systems. Each of these more conventional approaches has its own drawbacks: use of steam reduces total potential recovered heat due to the pinch points, hot water at high temperature requires high pressures for double-effect chillers, and direct exhaust firing involves very large ducts to transport the exhaust gases and generally involves greater backpressure on turbines, which can reduce electric generator output.

In addition to eliminating space to accommodate HRSG footprint, the above alternative facilitates use of prefabricated steam generators, associated heat exchangers, and pumping systems employing low-pressure, nonvolatile, recirculating heat-transfer fluids capable of direct extraction of turbine exhaust gas waste heat to generate steam and allow cascading the remaining captured waste heat to drive absorption chiller(s). The heat transfer fluid can also be used for space and domestic hot water systems enabling greater utilization of available heat reclamation potentials in satisfying highly variable annual building power, heating, and cooling load demands. This is achieved through maintaining favorable log-mean-temperature-differences (LMTDs) at the turbine gas extraction coil also resulting in a lower exhaust gas temperature discharge to ambient (see case study 6).

Types of Thermally Activated Technologies

In addition to using recovered waste heat for space heating, for example, waste heat, as noted, can also be used for cooling. Specifically, instead of electric motor power to rotate a refrigerant compressor, cooling can be generated in an absorption or adsorption process. As discussed in Chap. 4, one method is to use an absorption chiller, which typically uses the water/ammonia cycle to transfer and reject heat. Absorption chillers can either be single-stage, double-stage, or triple-effect, and can provide simultaneous heating and cooling. Absorption chillers are typically limited to a chilled water supply temperature of 42°F, although advanced control of solution concentrations can reportedly “lower the bar” a couple of degrees. As noted, steam can be produced in a HRSG, and that steam can be used to run a steam-turbine-driven centrifugal chiller, which can produce chilled water at a much lower temperature than 42°F, if needed.

In humid climates, waste heat can be used to remove moisture from thermally powered solid or liquid desiccant dryers and offers an excellent opportunity for sustainable energy savings versus electric-powered refrigerated dryers.

Understanding and Matching Facility Load Requirements

In an ideal case, the amount of recoverable heat from the prime mover tracks the power load; however, in reality, perfectly matched power and thermal requirements are not always possible. In brief, the following methods can be used to match the required on-site power and thermal energy:

- Match the thermal-electric ratio (see Chap. 4) of the prime mover to that of the user’s hourly load profile.
- Store excess power as chilled water or ice when the thermal demand exceeds the coincident power demand.

- Store excess thermal production as heat when the power demand exceeds the heat demand; either cool or heat storage must be able to productively discharge most of its energy before it is dissipated to the environment.
- Sell excess power or heat through approved paralleling protocols on a mutually acceptable contract basis to a user outside of the host facility (off-site). Often the buyer is the local utility, but sometimes it is nearby or “over the fence.”

Quality of Heat

The quality (temperature and pressure) of recovered energy needed by the facility is another major determinant in selecting the prime mover. If high-pressure steam is required using a topping-cycle, the only option is to use a CTG with a HRSG.

General System Sizing

As discussed in this book, proper CHP system sizing is critical to the sustainability of a CHP system. For example, if a CHP system is oversized, it is likely that the facility will not fully be able to utilize the waste heat, heat dumping will occur, overall system efficiencies will be low, and economic expectations may not be realized. If a CHP system is undersized electric and thermal loads may not be served and economic opportunities will be forgone, for example.

Note that CHP systems fall into two process categories:

1. *Topping-cycle.* A CHP process in which the energy input to the system is first used to produce useful power output, and at least some of the rejected heat from the power production process is then used to provide useful thermal energy to the facilities.
2. *Bottoming-cycle.* A CHP process in which the energy input to the system is first applied to produce useful thermal energy, and at least some of the rejected heat emerging from the thermal application is then used for power production.

Bottoming-cycles are typically used for facilities or industries that are heat load driven. That is, facilities that typically require large amounts of heat for their process. The topping-cycle has several variations and can be sized to meet the following:

- A portion of the facilities electric load (peaking plant)
- The facilities base electric load
- The facilities total peak electric load
- A portion of the facilities thermal load
- The facilities base thermal load
- The facilities peak thermal load

Unless power or thermal energy is to be exported from the site, the sizing variations listed above sets the “edges of the envelope” with respect to CHP plant size, and as discussed in Chap. 8 the various options need to be carefully studied. For example, a CHP plant sized to meet the peak electric demand provides maximum energy cost savings and maximum reliability, but may be large and relatively expensive to construct. Further, for many of the hours in a year, the peak demand cogeneration system

is oversized. Power sales to the electric utility are often not economical, and sometimes not allowed. Also, in this case, a large portion of the thermal energy from the peak electric load CHP plant may be wasted (i.e., rejected to the atmosphere) and regulated CHP efficiency requirements may not be met (e.g., FERC).

Full utilization of a CHP plant, electrically and thermally, typically results in better economic performance. An optimally sized CHP system uses as much of the recovered useful thermal energy as possible, with minimum heat dumping or wasting of recovered heat. Note it is possible, due to high electric demand utility charges, that a cogeneration plant sized for the peak electric load could provide higher total life-cycle cost savings (see Chap. 9), even though some of the recovered thermal energy is wasted or the generator is not fully utilized during some portions of the year. As part of a CHP general screening study, project engineers obtain historical data or develop estimates of electrical and thermal energy use. It is critical to evaluate the daily profile of energy use (i.e., energy use versus time). As noted, the relationship between electric energy demand and coincident thermal energy demand is critical. For example, a facility that has high electricity use during the daytime with little electricity use at night, and has high thermal energy requirements at night (e.g., for space heating) with little thermal energy use during the day is usually a poor cogeneration candidate unless a thermal storage strategy is incorporated. In general, CHP favors facilities that have coincident electric and thermal loads.

Environmental Impacts and Controls

Some key considerations in any CHP system are the following: What are the emissions from the CHP engine? What emission control strategies are necessary to comply with local and federal air quality regulations (not to mention to make the CHP plant as environmentally friendly as is economically justified)? The following is a brief description of some of the atmospheric pollutants that are found in combustion exhaust from CHP facilities:

Atmospheric pollutants. Pollutants generated by gas engines and turbine emissions include nitrogen oxides (NO_x), carbon monoxide (CO), hydrocarbons (HC), and sulfur oxides (SO_x). Aldehydes (CHO) and particulate matter $10\text{ }\mu\text{m}$ and smaller (PM_{10}), are also considered atmospheric pollutants. These atmospheric pollutants occur at extremely low concentrations in gaseous fuel applications when compared to liquid fuel applications.

Nitrogen oxides. Nitrogen oxides (NO_x) is formed in the combustion chamber by the combination of high temperatures and the presence of nitrogen and oxygen. The reaction between nitrogen (N_2) and oxygen (O_2) forms nitric oxide (NO) and nitrogen dioxide (NO_2) collectively referred to as NO_x . NO_2 is harmful to animals and humans because it limits breathing capacity and the ability of blood to carry oxygen. In the lower atmosphere, when exposed to sunlight, NO and NO_2 act as precursors to the formation of ozone.

Carbon monoxide. Carbon monoxide (CO) is formed by the incomplete combustion of fuel and oxygen. The complete combustion of a fuel, like methane (CH_4), and oxygen will produce carbon dioxide (CO_2) and water. The incomplete combustion of methane will form CO, CO_2 , and water. Carbon monoxide is a poisonous gas. In the upper atmosphere, it reacts with ozone (O_3) to form CO_2 , a greenhouse gas.

Hydrocarbons. Natural gas, which is comprised of methane, ethane, propane, butane, and other heavier compounds, is a typical fuel for CHP facilities. Typically, a small amount of hydrocarbons from the fuel source passes through the combustion chamber without combusting. Nonmethane hydrocarbons (NMHC) can react with the nitrogen oxides in the lower atmosphere and act as precursors to the formation of photochemical smog.

Sulfur oxides. Sulfur oxides (SO_x) are formed when sulfur compounds in the fuel and lube oil are oxidized in the combustion chamber. Sulfur oxides contained in the exhaust

stream combines with water vapor in the atmosphere to form sulfurous acid (H_2SO_3) and sulfuric acid (H_2SO_4). These acids are released from the atmosphere as acid rain.

Limiting and reducing emissions from CHP plants is an important element of sustainability. However, as discussed, the implementation of CHP by itself versus conventional methods (i.e., buying power from the utility company and burning gas in a boiler to make hot water or steam) reduces source fuel consumption and overall total emissions. Further, as mentioned, the use of biofuels may further negate the impact of CHP plant emissions as CO_2 , for example, is absorbed as crops are grown for fuel.

Emission controls are discussed in detail in Chap. 7, and the type of emission control system used depends upon the type of prime mover used. For example, reciprocating IC engines are either rich-burn or lean-burn, and the type of engine has an effect on the emission controls used to reduce emissions. In general, except for NMHC, the lean-burn combustion engine provides much lower levels of atmospheric pollutants. The lean-burn combustion engine is capable of producing lower emissions than a rich-burn engine before the aid of exhaust treatment and fuel-air ratio controllers.

As the amount of thermal NO_x generated is related linearly to the amount of time that the hot gases are at flame temperature in the combustor, and exponentially to the temperature of the flame, some CTG emission control systems work to cool the flame temperature. For example, wet injection is an emission control technique in which water or steam is injected into the combustor to lower the flame temperature, which lowers the formation of NO_x . Steam injection can increase the power output of a turbine by increasing the mass flow rates.

Exhaust gas treatment involves further reducing the levels of atmospheric pollutants present in exhaust by “cleaning” these pollutants from the exhaust stream. Catalysts are a common method of reducing the amount of atmospheric pollutants present in exhaust gas. Catalysts are used to reduce pollutants in exhaust emissions by chemically converting them into naturally occurring compounds. A catalyst sustains a chemical reaction without being chemically changed. The catalyst will either oxidize or reduce chemical compounds. Common catalyst types include three-way catalysts and selective catalytic reduction (SCR).

Key Issues Facing Industry Today

As this book was being written, the world experienced extreme energy price volatility that in part led to food riots around the world as commodity prices surged. Crude oil peaked around \$150 per barrel in summer of 2008, and in the United States, natural gas reached more than \$14 per million Btu (decatherm), but is now less than \$4 per decatherm. The sharp decline of the world economy in late 2008 sent crude oil prices below \$40 per barrel in the span of just about 4 months. In the global economy, we are apparently all connected, and CHP plants, which today typically use fossil fuels, experienced economic challenges as fuel prices escalated and utility electricity rates lagged fuel price increases. Utility escalation rates often lag fuel prices due to the inherent system inertia, regulatory requirements, and political hurdles that utilities face in obtaining a rate increase. High fuel prices and relatively low electricity prices hurt the economic viability of existing and proposed CHP systems. As many utilities use fossil fuel as their main energy input, eventually electricity rates rise to reflect the cost of the fuel source, or as it is today that when fuel prices fall, operating CHP plants benefit from their investments.

A promising alternative to using fossil fuels to power CHP plants is the use of biofuels (liquid and gas). Today, biogas from wastewater treatment plants and landfills (landfill gas) is routinely used to fuel CHP systems, and some systems are beginning to be powered from liquid biofuels including biodiesel made from waste oils or vegetable oils or plant oils. With respect to ethanol, however, some controversy exists as corn is used in the making of ethanol and the increased demand for ethanol contributed to the surge in food prices (corn is a staple of many manufactured food products as well as feed for livestock). Scientists are working on ways to produce biofuel from switch grass and other cellulose waste products or from algae or from fast growing plants that can grow in poor soil with little water or fertilizer instead of from food stock. As noted, one benefit of biofuels is that CO_2 is resequistered during the growing cycle removing carbon from the atmosphere to help reduce global warming.

Today, we are facing the challenges of climate change, global warming, and how to reduce greenhouse gas emissions. ASHRAE's policy statement on global warming in effect acknowledges that greenhouse gases are linked to global warming and that greenhouse gas emissions must now be taken seriously by its members and by the world community. Architects and engineers responsible for engineered building facilities lasting 30 to 40 years minimum on average or longer can minimize such global warming impacts well into the future by advocating sustainability through cost-effective CHP today. Energy experts know that there is no "silver bullet" (to use a horror mythology metaphor), but there is "silver buckshot," meaning that there are a lot of little things that, added together, will make a significant difference. Energy experts and government officials strategic plan for both the short and long term is to increase the use of CHP because of its inherent high source fuel utilization efficiency. Further, ASHRAE building sustainability goals are likely to be significantly advanced through efficient and value-based on-site sustainable CHP systems differentiated using life-cycle cost analysis and eco-footprint methods. Improvements continue to reduce CHP plant emissions, and new generation equipment and emission controls are achieving orders of magnitude reductions in emissions when compared to earlier years.

The centralized plants of large energy users, for example, hospitals, universities, or research campuses are ideal candidates for CHP installations. However, evaluating costs and benefits can make ROI projections difficult, especially with new facilities that lack historical operating data. Fortunately, in such cases, CHP engineers can readily find and employ thoroughly tested CHP optimization software as a valuable resource for evaluating alternative approaches during the projects feasibility study phase. Ultimately, the feasibility of any CHP approach will depend on the magnitude, duration, and coincidence of electrical and thermal loads and on the selection of the prime movers and the waste heat recovery systems.

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Applicability of CHP Systems

Itzhak Maor

T. Agami Reddy

Background

Combined heat and power (CHP) systems offer great promise in alleviating some of the looming problems of increased energy demands and peak power issues arising from deregulation of the electric market, petroleum shortages and the drive for better energy efficiency. This chapter discusses the applicability of CHP systems for commercial and industrial applications. Since the terminology used by different publications is confusing and sometimes conflicting, we start with defining relevant key terms to CHP systems in general.

The distributed power utility seems to have evolved in four directions:

1. *Large-scale/wholesale electric power generation systems* (sizes in the range of 400 to 1000 MW), primarily meant to sell power to an electric utility. The sizing of such microgrid systems is dictated by power purchase agreements rather than by site requirements of electric power and heat (Orlando 1996).
2. *District energy and industrial/agricultural CHP systems* (sizes ranging from 3 to 50 MW) for process applications that require almost constant thermal and electric loads to be met year-round. These systems are meant for industrial/agricultural process applications (ICHP) and for district energy systems involving large campuses as well as clusters of residential units in a neighborhood.
3. *Building CHP (BCHP) systems* (sizes in the range of 50 kW to 3 MW) for individual buildings and small campuses where the intent is to reduce electric power purchases from the local utility by either generating electricity on-site and using the waste heat to reduce boiler heating requirements (topping-cycle), or recover the waste heat from the boiler exhaust to generate electricity (bottoming-cycle).
4. *Micro-CHP systems* (sizes in the range of 3 to 20 kW) meant for individual residential and small-scale applications.

Distributed energy resource (DER) is a term used to denote an on-site power system involving electric generation units (typically in the range of 3 kW to 50 MW) that are either stand-alone or in parallel with the electric distribution system strategically placed at or near the end user facility (Shipley et al. 2001). Under this perspective, DER would apply to categories (2) through (4) described above. Within the electric industry, the following terms have also been used (Shipley et al. 2001):

1. *Distributed generation (DG)*. It is defined as anything outside of the conventional utility grid that produces electricity. DG includes nonutility CHP plants, and backup generators. DG technologies include internal combustion engines, fuel cells, gas turbines, and microturbines, as well as hydro and microhydro applications, photovoltaic, wind energy, and solar energy.
2. *Distributed power (DP)*. It encompasses all of the technologies included in DG as well as electrical storage technologies. DP includes batteries, flywheels, modular pumped hydroelectric power, regenerative fuel cells, superconducting magnetic energy storage, and ultracapacitors.
3. *Distributed energy resource (DER)*. It involves any technology that is included in DG and DP as well as demand-side measures. Under this configuration, power can be sold back to the grid where permitted by regulation.
4. *Power-only applications*:
 - (a) Standby power required by fire and safety codes for hospitals, water pumping, critical loads, and other such applications
 - (b) Base load power or primary power that is less expensive to produce locally than it is to purchase from the electric utility (continuous on-site power)
 - (c) Demand response peaking on-site generation used in coordinated peak shaving programs with the service utility
 - (d) Customer peak shaving equipment used by the customer to reduce the cost of peak load power
 - (e) Premium power used for reduced frequency variations, voltage transients, surges, dips, or other disruptions
 - (f) Grid support equipment used by utilities for peaking or intermediate load
5. *Combined power and heat applications*. Thermal energy from a single energy source drives the DER equipment, which is meant to simultaneously meet (in whole or in part) the electrical or mechanical energy (power) and thermal load of
 - (a) A single building, group of buildings, a single campus: BCHP plants
 - (b) Process heat and power needs of an industrial/agricultural unit: ICHP plants
6. *DER technologies*. It includes the systems, equipments, and subsystems used to support the DER applications. These include the following prime movers:
 - (a) Reciprocating engines (spark ignition or compression ignition)
 - (b) Gas turbines
 - (c) Microturbines
 - (d) Steam turbines
 - (e) Fuel cells

As stated previously, CHP is a specific application of DER. Several synonymous terms have been used for CHP (MAC 2005):

- Cogen—cogeneration: combined production of both useful heat and power
- BCHP—building cooling, heating, and power
- CHPB—cooling, heating, and power for buildings
- CCHP—combined cooling, heating, and power
- Trigen—trigeneration: combined production of useful heating, cooling, and power
- TES—total energy systems
- IES—integrated energy systems

In order to keep consistency, only the term CHP or BCHP has been used in this chapter. Some of the desirable conditions for BCHP to be competitive are

- Good coincidence between electric and thermal loads
- Thermal energy requirements in the form of hot water or steam
- Electric demand-to-thermal demand ratios ranging from 0.5 to 2.5
- Cost differential between electricity (total cost) and natural gas (total cost) of greater than \$12/10⁶ Btu
- Moderate to high operating hours (greater than 4000 hours per year)
- When electric power quality and reliability are important considerations
- Larger size building/facility, which allows lower initial cost of BCHP and larger annual savings

Given these conditions, potential candidates for CHP can be grouped in two categories as

1. *Commercial/institutional facilities (BCHP)*. Hospitals and other health-care facilities, hotels, universities and educational facilities, supermarkets, large residential buildings or complexes, research and development and laboratory buildings, large office buildings, military bases, and district energy systems
2. *Industrial facilities (ICHP)*. Chemical manufacturing, pharmaceutical and nutritional units, food processing units, and pulp and paper mills

Given the uniqueness of industrial facilities, this chapter covers in detail the commercial and institutional sectors wherein CHP systems are relevant. Detailed information on CHP in the industrial sector can be found in “The Market and Technical Potential for Combined Heat and Power in the Industrial Sector,” a report by the Onsite Sycom Energy Corporation (Onsite 2000).

Applicability of CHP to Commercial and Institutional Facilities

It is difficult to precisely define the commercial and the institutional sectors given the broad range of their activities. Commercial applications are typically driven by the energy used in the building unlike industrial processes which are driven by manufacturing requirements. In many commercial applications, the thermal load is not coincident with the electrical load due to strong dependency on seasonal variations, and also due the limited operating hours.

For example, an office building can be unoccupied in many cases more than 4000 hours per year. Industrial facilities, on the other hand, can operate 8760 hours per year with fairly constant electrical and thermal load. A good example is a nutritional manufacturing facility that has simultaneous high thermal and electrical demand. Given the characteristics of commercial facilities, a good understanding of the building loads is mandatory for efficient selection and sizing of the BCHP system. This section provides a background information on the applicability of BCHP to the commercial sector, and covers in detail such issues as which fuel is typically used for BCHP application, which building types are good candidates for BCHP, which climatic location is favorable for BCHP, and which are common types and sizes of prime movers. Under all circumstances a more rigorous analysis (feasibility study) will be required for the determination of the most cost-effective BCHP for a particular application; Part 2 Chap. 8 covers feasibility study methods in more detail.

In general, the applicability of CHP to commercial and institutional facilities is influenced by the following factors.

Prime Mover Fuel Type

Onsite Sycom Energy Corporation (Onsite 2000) utilized the Hagler and Bailly Independent Power Database (HBI) to develop a profile of exiting cogeneration activity in the commercial sector.

Pertinent consolidated total values across all sector/building types are shown in Table 2-1. Since natural gas (NG) is the leading fuel in existing CHP installations and also given the fact that technologies such as coal, wood, and waste heat are not as readily available (or feasible for commercial applications) or are environmentally restricted (such as oil), it is safe to assume that NG will continue to dominate the commercial BCHP market.

A newer report prepared for the U.S. Department of Energy, Energy Information Administration (Discovery Insights 2006) provides update of the CHP market status, but since the newer report doesn't provide detailed information on existing and potential applications for CHP systems (hospitals, hotels, education, and so on), the information in this chapter is based on Onsite Sycom Energy Corporation report (Onsite 2000).

Building Type (Sector) and Size

The applicability of BCHP is based on previous experience and future potential. This section is based on Onsite Sycom Energy Corporation study (Onsite 2000) and includes both existing BCHP installations and potential ones. Table 2-2 lists all the commercial applications covered by Onsite Sycom Energy Corporation study (Onsite 2000).

Variable \ Fuel Type	Coal (%)	Natural Gas (%)	Oil (%)	Waste (%)	Wood (%)	Other (%)	Total (%)
Number of installations	1.8	88.4	3.1	2.6	0.4	3.7	100.0
Total power (MW)	8.9	72.0	2.2	13.3	0.9	2.7	100.0
Total heat (10 ⁶ Btu/h)	15.5	52.7	3.9	23.4	1.9	2.6	100.0

Source: Based on Onsite (2000).

TABLE 2.1 Fuel Use Distribution of Existing CHP Plants

No.	Sector/ Buildings	Number of Buildings		Electrical Power of Buildings		Thermal Capacity of Buildings	
		Number of Buildings	% of Total Buildings	Electrical Power (MW)	% of Total Electrical Power	Thermal Heat (10 ⁶ Btu/h)	Thermal Heat (%)
1	Warehousing	4	0.4	58	1.6	233	1.8
2	Airports	7	0.8	151	4.3	606	4.7
3	Water treatment	12	1.4	116	3.3	464	3.6
4	Solid waste	0	0.0	0	0.0	0	0.00
5	District energy	16	1.8	728	20.5	1,959	15.2
6	Food stores	10	1.2	1	<0.1	6	<0.1
7	Restaurants	11	1.3	1	<0.1	4	<0.1
8	Commercial office buildings	45	5.2	110	3.1	569	4.4
9	Apartments buildings	97	11.2	95	2.7	650	5.0
10	Hotels	78	9.0	26	0.7	136	1.0
11	Laundries	76	8.8	3	0.1	13	0.1
12	Car wash	2	0.2	<1	<0.1	1	<0.1
13	Health and country clubs	81	9.4	163	4.6	403	3.1
14	Nursing homes	72	8.3	10	0.3	41	0.3
15	Hospitals	119	13.8	413	11.7	1,593	12.3
16	Elementary and primary schools	101	11.7	14	0.4	55	0.4
17	Colleges and universities	93	10.7	1,104	31.1	3,856	29.9
18	Museums	2	0.2	4	0.1	30	0.2
19	Government facilities	26	3.0	501	14.1	2,105	16.3
20	Prisons	14	1.6	48	1.4	195	1.5
	Total	866	100.0	3,547	100.0	12,919	100.0

Source: Based on Onsite (2000).

TABLE 2.2 Listing of Existing BCHP Plants by Sector

Unlike the case for existing BCHP installations, Onsite utilizes the MarketPlace Database (based on Dun and Bradstreet financial listing) from iMarket Inc. to identify potential segment for future BCHP installations. The potential CHP installation (or the size of the prime mover) was based on *average electrical demand for each sector*. Four groups were selected to represent the sector average electrical demand: (a) 100 to 500 kW, (b) 500 to 1000 kW, (c) 1.0 to 5.0 MW, and (d) more than 5.0 MW. Tables 2-3 to 2-5 show all the potential sectors based on number of establishments and potential electrical power generation (MW), respectively.

No.	Sector/ Buildings	Total Establishments	Potential Establishments				Total CHP Potential Establishments
			100– 500 kW	500– 1,000 kW	1,000– 5,000 kW	>5,000 kW	
1	Hotels	66,400	12,010	895	540	220	13,665
2	Nursing homes	19,200	4,610	4,050	1,570	25	10,255
3	Hospitals	16,400	2,945	1,290	2,110	215	6,560
4	Schools	123,890	32,400	9,690	390	0	42,480
5	College/ universities	4,090	1,005	580	680	205	2,470
6	Commercial/ laundries	7,275	830	400	10	0	1,240
7	Car wash	20,630	1,150	40	0	0	1,190
8	Health clubs/ spas	12,610	3,020	4,060	15	0	7,095
9	Golf clubs	14,040	3,800	820	205	30	4,855
10	Museums	9,090	330	290	50	0	670
11	Correctional facilities	3,950	1,190	740	610	45	2,585
12	Water treatment/ sanitary	8,770	2,055	490	65	0	2,610
13	Extended service restaurants	271,000	25,475	495	330	0	26,300
14	Supermarkets	148,000	16,300	1,160	140	0	17,600
15	Refrigerated warehouse	1,460	595	640	75	5	1,315
16	Office buildings	705,000	57,000	12,000	2,900	290	72,190
	Total establishments	1,431,805	164,715	37,640	9,690	1,035	213,080
	Total (%)		77.3	17.7	4.5	0.5	100.0

Source: Based on Onsite (2000).

TABLE 2.3 BCHP Potential by Number of Establishments

No.	Sector/ Buildings	Electrical Capacity				Total CHP MW Potential	Total CHP MW Potential (%)
		100– 500 kW	500– 1,000 kW	1,000– 5,000 kW	>5,000 kW		
1	Office buildings	7,532	5,055	4,362	1,665	18,614	24.1
2	Schools	7,130	6,781	973	0	14,884	19.3
3	Hospitals	647	904	5,275	2,052	8,878	11.5
4	Nursing homes	1,014	2,837	3,923	219	7,993	10.3
5	Hotels	2,642	627	1,353	2,081	6,703	8.7
6	College/ universities	221	407	1,693	1,929	4,250	5.5
7	Health clubs/ spas	665	2,839	48	0	3,552	4.6
8	Extended service restaurants	2,802	173	415	0	3,390	4.4
9	Correctional facilities	261	517	1,515	428	2,721	3.5
10	Golf clubs	836	574	513	285	2,208	2.9
11	Supermarkets	897	203	84	0	1,184	1.5
12	Water treatment/ sanitary	452	342	155	0	949	1.2
13	Refrigerated warehouse	131	448	183	30	792	1.0
14	Commercial/ laundries	183	279	23	0	485	0.6
15	Museums	73	202	123	0	398	0.5
16	Car wash	253	28	0	0	281	0.4
	Total power (MW)	25,739	22,216	20,638	8,689	77,282	100.0
	Total (%)	33.3	28.8	26.7	11.2	100.0	

Source: Based on Onsite (2000).

TABLE 2-4 BCHP Potential by Electrical Power Average Demand (MW) Sorted from Highest to Lowest

No.	Sector/ Buildings	Total Potential (MW)	Installed CHP (MW)	Remaining Potential (MW)	Total CHP MW Potential (%)
1	Office buildings	18,614	235	18,379	24.6
2	Schools	14,884	14	14,870	19.9
3	Hospitals	8,878	491	8,387	11.2
4	Nursing homes	7,993	11	7,982	10.7
5	Hotels	6,703	30	6,673	8.9
6	College/ universities	4,250	1,414	2,836	3.8
7	Health clubs/ spas	3,552	164	3,388	4.5
8	Extended service restaurants	3,390	1	3,389	4.5
9	Correctional facilities	2,721	135	2,586	3.4
10	Golf clubs	2,208	0	2,208	3.0
11	Supermarkets	1,184	1	1,183	1.6
12	Water treatment/ sanitary	949	141	808	1.1
13	Refrigerated warehouse	792	0	792	1.1
14	Commercial/ laundries	485	3	482	0.7
15	Museums	398	4	394	0.5
16	Car wash	281	0	281	0.4
17	Other	NA	2,282	NA	NA
	Total	77,282	4,926	74,638	100.0

Source: Based on Onsite (2000).

TABLE 2-5 Combined Existing and Potential BCHP by Electrical Power Average Demand (MW) Sorted from Highest to Lowest

It should be noted that from an average electrical power demand standpoint, the first five sectors (in Tables 2-4 and 2-5) represent approximately 75 percent of the total average electrical power demand of all the sectors.

Although the schools sector (second highest potential) does not differentiate between primary schools and secondary schools, a market analysis report by Ryan

(2004) clearly suggests that secondary (high) schools (from 9 through 12 grades) are more suitable for BCHP than primary (or K-8) schools for the following reasons:

1. Secondary schools are more likely to operate 12 months a year.
2. Secondary schools are more likely to contain an indoor swimming pool facility.
3. Secondary schools are more likely to operate into the evenings and weekends allowing longer period of BCHP operation.
4. Secondary schools typically contain gymnasiums with shower facilities.

It should be noted that the “office buildings” category specified in this study refers to office buildings with total area greater than 25,000 ft².

This information along with previous experience (existing installations) can be used as a starting point to identify sectors which are most appropriate for BCHP.

Climatic Regions

The selection of favorable climatic regions for BCHP has been handled in a manner similar to that of the building/sector. Onsite (2000) provides detailed information on geographic locations (states) of existing BCHP installations and also for potential/future installations. According to the study, 50 percent of potential BCHP installations have been identified in nine states: California, Illinois, Florida, Michigan, New Jersey, New York, Ohio, Pennsylvania, and Texas. Table 2-6 shows these states and the corresponding climatic zones.

ANSI/ASHRAE/IESNA Standard 90.1-2007, normative Appendix B (based on Briggs et al. 2003b) can be used to characterize the climate characteristics of these states. This standard correlates location to climatic region, by defining three major types of climatic types: moist (A), dry (B), and marine (C), in addition, the standard uses eight zone numbers starting from 1 (which is very hot region) and ends with 8 (which represents subarctic). For international locations the ANSI/ASHRAE/IESNA Standard 90.1-2007, normative Appendix B, Section B.2 can be used.

No.	State	Climatic Region	Zone Definition
1	CA	Mainly 3B	Warm-dry
	NY	Mainly 5A	Cool-humid
	PA	Mainly 5A	Cool-humid
2	MI	Mainly 5A	Cool-humid
	OH	Mainly 5A	Cool-humid
	IL	Mainly 5A	Cool-humid
3	NJ	Mainly 4A	Mixed-humid
4	FL	Mainly 2A	Hot-humid
5	TX	Mainly 3A	Warm-humid

TABLE 2-6 Geographic Locations of 50 Percent of Potential/Future BCHP Installations

Size Range	Boiler/ Steam Turbine	Combined Cycle	Combustion Turbine	Reciprocating Engine	Other	Total Number	Total (%)
0–999 kW	7	0	20	662	16	705	71.9
1.0–4.9 MW	15	0	42	83	0	140	14.3
5.0–9.9 MW	4	3	16	16	1	40	4.1
10.0–14.9 MW	3	0	11	7	2	23	2.3
15.0–19.9 MW	7	0	2	0	0	9	0.9
20.0–29.9 MW	5	6	5	2	0	18	1.8
30.0–49.9 MW	8	5	6	0	0	19	1.9
50.0–74.9 MW	11	4	0	0	0	15	1.5
75.0–99.9 MW	0	2	2	0	0	4	0.4
100–199 MW	0	5	0	0	0	5	0.5
200–499 MW	0	2	0	0	0	2	0.2
Total number	60	27	104	770	19	980	100.0
Total (%)	6.1	2.8	10.6	78.6	1.9	100.0	

Source: From Onsite (2000).

TABLE 2-7 Number of Existing CHP Installations

Basic Types and Size Range of BCHP Prime Movers

Several types of prime movers are applicable to the commercial sector. The selection of prime mover type and size will depend first on their size range, and second on their type. The selection approach was similar to the previous sections and involves looking at both existing and potential/future installations. Tables 2-7 and 2-8 assemble information on number of installations and their size range for existing commercial CHP installations.

Since the focus of this section is on buildings and commercial applications, the groups: boiler/steam turbines, combined cycles, and others were eliminated. This leaves us with combustion turbines and reciprocating engines as the prime movers most appropriate for this application. The number of existing installations utilizing reciprocating engines dominates the number of installations (78.6 percent). This together with the combustion turbine category represents approximately 90 percent of the installations; the total generated power is only 29 percent of the total. This can be explained by the fact that the two major categories (boiler/steam turbine and combined cycle or combustion turbine/HRSG) are utilized by large power generation facilities.

CHP systems can also operate on either a topping- or bottoming-cycle basis. In a topping-cycle, energy from the fuel source generates shaft or electric power, and waste thermal energy from the exiting turbine exhaust stream is recovered for other building application, for example, heat activated absorption chillers and/or domestic hot water and space heating systems. In a bottoming-cycle, shaft or electric power is generated from excess thermal energy available after higher-level thermal energy has been used to

Size Range	Boiler/ Steam Turbine	Combined Cycle	Combustion Turbine	Reciprocating Engine	Other	Total (MW)	Total (%)
0–999 kW	3.23	0.00	15.38	95.09	4.22	117.92	2.4
1.0–4.9 MW	37.06	0.00	118.21	182.02	0.00	337.29	6.8
5.0–9.9 MW	24.80	22.20	97.48	95.80	7.30	247.58	5.0
10.0–14.9 MW	34.00	0.00	139.37	86.60	24.50	284.47	5.8
15.0–19.9 MW	118.20	0.00	31.75	0.00	0.00	149.95	3.0
20.0–29.9 MW	119.70	170.05	130.20	46.30	0.00	466.25	9.5
30.0–49.9 MW	317.10	196.70	244.90	0.00	0.00	758.70	15.4
50.0–74.9 MW	687.00	241.50	0.00	0.00	0.00	928.50	18.8
75.0–99.9 MW	0.00	176.00	156.00	0.00	0.00	332.00	6.7
100–199 MW	0.00	759.47	0.00	0.00	0.00	759.47	15.4
200–499 MW	0.00	544.00	0.00	0.00	0.00	544.00	11.0
Total (MW)	1341.09	2109.92	933.29	505.81	36.02	4926.13	100.0
Total (%)	27.2	42.8	18.9	10.3	0.7	100.0	

Source: From Onsite (2000).

TABLE 2-8 Existing CHP Installations by Power Generated

satisfy thermal loads. A combined cycle uses thermal output from a prime mover to generate additional shaft power where its exhaust waste heat can be used to generate steam in an HRSG or by means of heat exchanger utilizing heat transfer media in lieu of an HRSG as described earlier in Chap. 1 to drive a steam turbine generator.

The above referenced combined cycle is employed in larger utility CHP systems and are beyond the scope of this book. It is also important to note here that microturbine technology was not clearly considered by Onsite during their investigation. We will add this technology as a viable system for BCHP in view of the increasing popularity of microturbines, and given the fact that this technology can be economical in smaller facilities (100 to 500 kW average electrical demand). Hence, the following prime movers were identified as prime candidates for the BCHP sector: (a) reciprocating engines, (b) combustion turbines, and (c) microturbines.

The potential for BCHP based on prime mover size is shown in Table 2-4. The prime mover size distribution is plotted in Fig. 2-1. As shown, the dominant size range for the average electrical power (or demand) is from 100 to 5000 kW. MAC (2005) suggests the use of rule of thumb based on annual thermal-electric (T/E) ratio for selecting the type of prime mover (see Table 2-9).

ASHRAE (2003), Chapter 35, Table 2B was used to calculate T/E of the selected building sectors which are shown in Table 2.10.

The calculated T/E results for these examples are clearly in the range 0.43 to 1.22 which seems to be more applicable for reciprocating engines (lean burn and rich burn). Figure 2-2, depicts the ranges of each prime mover technology and market size coverage. As shown, reciprocating engines clearly dominate in sizes ranging from 100 to

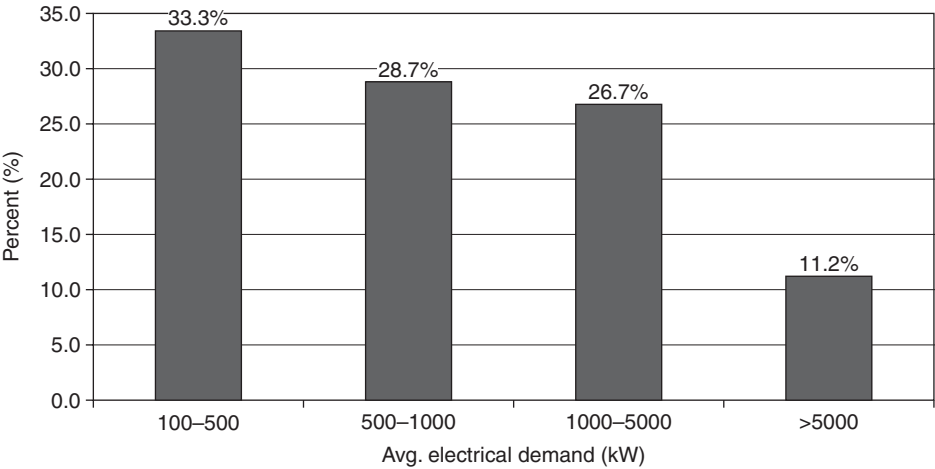


FIGURE 2-1 Potential BCHP electrical power generation by average electrical demand. [From Onsite (2000).]

T/E Value*	Recommendation
0.5–1.5	Consider engines
1.0–10.0	Consider gas turbine

*T is the total thermal energy used (total gas usage × boiler or equipment efficiency) [Btu], and E is the total electrical energy used (total electrical usage [kWh] × 3413) [Btu].

TABLE 2-9 Rule of Thumb Utilizing Annual Thermal-Electric Ratio (T/E)

Building/Sector	Electrical	Thermal		T/E Value
		Input	Output	
	10 ³ Btu/ft ²	10 ³ Btu/ft ²	10 ³ Btu/ft ²	
Office	64.5	36.7	27.5	0.43
Education (schools)	28.7	42.3	31.7	1.11
Health care (hospitals)	90.4	146.9	110.2	1.22
Lodging (hotels)	52.0	75.2	56.4	1.08

Notes: 75% efficiency used to calculate the thermal output.
ASHRAE 2003, Chapter 35, Table 2B does not state if educational facilities include college/universities.
Source: Based on ASHRAE 2003, Chapter 35 Table 2B [based on DOE/EIA 0318(95), (1998)].

TABLE 2-10 Thermal-Electric (T/E) Ratio for the Selected Buildings/Sectors

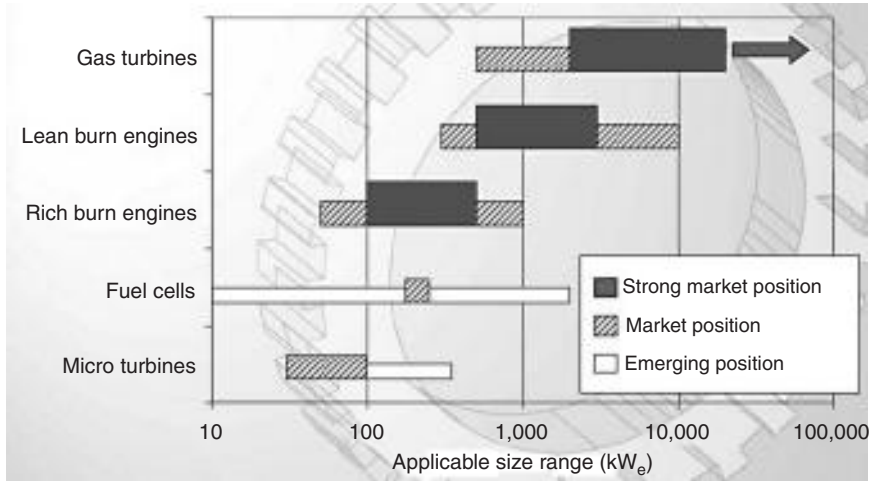


FIGURE 2-2 Prime mover technology by size and market coverage. [From Bluestain (2001).]

5000 kW. Combustion turbines start from approximately 3000 kW. Although the figure shows that microturbines are positioned in sizes smaller than 100 kW, new microturbines larger than 100 kW are currently available.

Typical efficiency for each prime mover can be seen in Fig. 2-3. We note that gas-fired reciprocating engines have superior fuel-to-electricity conversion efficiency compared to gas turbines.

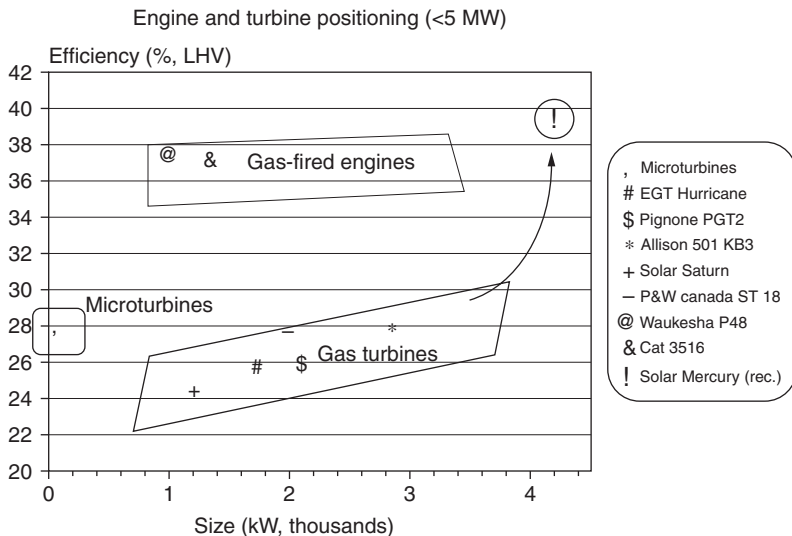


FIGURE 2-3 Prime mover technology efficiency. [From Hedman (2001); source: GTI and Onsite Energy.]

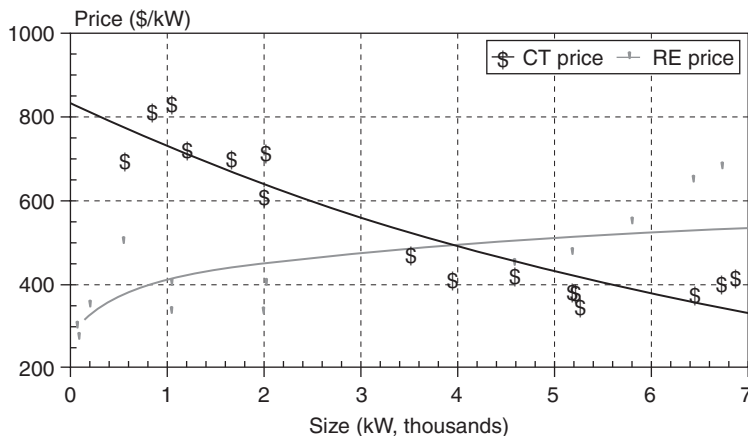


FIGURE 2-4 Price of prime mover technology. [Note: Actual purchase prices may vary due to market conditions and other factors. Prices do not include gas compressors (if required).] [From Hedman (2001); source: Gas Turbine World/SFA Pacific/GRI.]

Typical costs of each prime mover shown in Fig. 2-4 provide a convenient cost comparison of gas turbine and reciprocating engines. It should be noted that the cost shown is the equipment cost only and not fully constructed system.

In deciding on the type of the prime mover, the designer can also consider taking into account the following: Combustion gas turbines have the advantage of higher thermal waste heat than reciprocating engines and the ability to generate high-pressure (HP) steam. These make combustion gas turbines attractive in industrial facilities with high thermal energy needs. In commercial applications, however, a high electrical generation efficiency is typically more desirable which makes reciprocating engines more applicable (and cost-effective) for these applications.

In contrast to industrial applications, which need HP and/or LP (low-pressure) steam, commercial buildings typically need hot water (or LP steam) for space heating and DHW. Reciprocating engines can effectively meet these requirements. It is important to indicate that hospitals need higher-pressure steam for sterilizers, but the capacity and the annual usage is relatively low as compared to the total thermal energy use. In order to satisfy this need, it is likely more efficient to design a system with a small HP steam generator dedicated to sterilizers. Reciprocating engines are well suited for packaged CHP in commercial and light industrial applications for less than 5 MW (EPA 2002).

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Power Equipment and Systems

Lucas B. Hyman

Adam Stadnik

As discussed in previous chapters, combined heat and power (CHP), sometimes called cogeneration, trigeneration, integrated energy systems, or total energy systems, derives both electrical (or mechanical) power and useful heat from the same fuel source. With any CHP method, the power and the heat are derived from the oxidation of a fuel. In general, the processes fall into two major groups. One group burns (oxidizes) the fuel to produce heat in order to produce rotary power for electricity, where heat is a by-product. The second group derives electricity directly from the chemical process of oxidation of fuel, and again heat is a by-product.

In the most common group, fuel is directly burned in a prime mover process. This group includes internal combustion engines and combustion turbines. In each case, oxidation of the fuel provides heat and the expansion of gases. The expanding gases drive a mechanical process which outputs rotary power to drive an electrical generator. With internal combustion, the hot gases expand inside a cylinder with a piston and the expansion drives the piston. These prime movers are called internal combustion engines and are closely related to vehicle engines. This group includes ones with a spark igniter and ones which use heat of compression to ignite the fuel (diesel cycle) as discussed further in this chapter.

In a combustion turbine, a hot compressed gas and air mixture produced by combustion is allowed to expand through turbine blades, which produces rotary power for electrical generation.

A second group of fuel-fired systems burns the fuel in a boiler to produce high-pressure and often superheated steam. The steam produced is delivered to a steam turbine. Expansion of steam through the turbine blades produces rotary power which drives an electrical generator. The steam turbine process is often used in large commercial electrical generation plants.

When a steam turbine process is used in CHP, the energy lost in condensing is put to use in heating or cooling buildings or processes. For this to work, the discharged

steam from the turbine must be piped to a low-pressure steam heat use, which is needed at the same time as the steam turbine. Therefore, there must be a balance between a thermal load which can be supplied by the turbine exhaust steam and the power output of the steam turbine. Supplemental boilers and thermal storage can help balance loads. The temperature and pressure of the exhaust steam must match the load requirements. The lower the temperature and pressure needed by the facility, the more energy available to the steam turbine.

Boilers and steam-driven turbines offer more flexibility in the fuel which drives the process. Any fuel which can be burned in a boiler or waste heat derived from a process can produce the steam necessary to drive a steam turbine. A special application is combined cycle where waste heat from a gas-fired combustion turbine produces steam which drives a steam turbine or is injected back into the combustion turbine for additional power (Cheng cycle). A common application today is to install a backpressure steam turbine in an existing steam boiler and steam distribution system. Boilers are sometimes operated at higher pressure than is required to deliver the steam, and with a backpressure steam turbine, steam expands through the turbine to the lower pressure needed to deliver the steam to the loads served producing power as a by-product. Where the needed components exist, such a system is highly efficient and low-cost.

As discussed later in this chapter, a fuel cell is a special process that does not depend on mechanical energy to produce electricity. A chemical reaction occurs within the cells from the union of hydrogen and oxygen. The products of that chemical reaction are electrical energy, water vapor, and heat. The source of the hydrogen is often natural gas. In CHP plants, the waste heat is used to meet the thermal energy needs of buildings or processes. The temperature of the waste heat depends on the specific fuel cell process. While the temperature in some fuel cell processes is quite low, in other processes, the waste heat temperature is high enough to produce steam for a combined process.

The prime mover is the heart of a CHP system. The power produced by the prime mover is typically used to generate electricity but can also be used for mechanical power to drive pumps, chillers, and compressors, for example. As noted, heat may be produced directly in the prime mover and/or heat recovery takes place in the prime mover exhaust stream. Heat recovery for producing additional power, hot water, steam, chilled water, and/or desiccant humidification is a critical component of CHP systems and is discussed further in Chap. 4.

A prime mover CHP process develops rotary power to drive an electrical generator or other rotary equipments such as fans or pumps. CHP prime movers come in two varieties: fuel-to-power equipments and thermal-to-power equipments. Fuel-to-power prime mover equipments are fired with gaseous fuels such as natural gas, methane from wastewater plants or landfills, or liquid fuels such as light oils, biofuels (a growing important part of enhanced CHP sustainability), alcohol, or other biomass in a combustion process to mechanically create power for use by the building, industry, or facility.

Fuel cells are a fuel-to-energy process, but do not produce rotary power, and are not, therefore, prime movers.

As discussed in Chap. 2, natural gas (NG) is often the preferred fuel as it is readily available via a nationwide distribution system. Natural gas is cleaner than fuel oil, coal, wood, or agricultural waste, since more of NG energy content comes from hydrogen so NG has less carbon footprint than most other fuels. NG, therefore, may not have the environmental problems associated with other such fuels.

Typical fuel-to-power equipment includes

- Internal combustion (IC) reciprocating engine generators
 - Spark ignition
 - Diesel cycle
- Combustion turbine generators (CTGs)
 - Aircraft derived (aero-derivative) turbines
 - Stationary/industrial turbines
 - Microturbines
- Fuel cells

Thermal-to-power prime mover equipment includes processes where heat is developed by a source outside the prime mover. This includes both, boiler-produced steam and waste heat derived from another process. It also includes processes where waste heat is generated by one of the primary prime movers discussed above. When the steam is derived from one of the prime mover processes listed above and is used to generate additional power, the process, as mentioned, is called a *combined cycle*.

Typical thermal-to-power equipment includes

- Steam turbines
- Steam-driven reciprocating engines
- Stirling engines (external combustion engines)
- Organic Rankine cycles

Steam-driven reciprocating engines and Stirling engines are not commonly used today, although steam reciprocating engines were quite common in the past, and Stirling engines have recently been coupled with solar mirrors to provide the highest solar-to-electric conversion efficiency yet achieved. Stirling engines are classified as external combustion engines, where heat on the outside of a cylinder drives a piston and the gas in the cylinder is expanded and then contracted as the cylinder is cooled. Fuel burned on the outside or waste heat from some process heats the gases inside the cylinder to drive the piston. Cooling the cylinder drives the piston back to its original position. Organic Rankine cycles are typical Rankine cycles, except that they use an organic working fluid instead of the standard steam/condensate and can operate with relatively low temperature heat sources. Both types of thermal-to-power prime mover systems are relatively small in their number of CHP installations, and their power output capacity, typically, is also small, therefore, Stirling engines, steam-driven reciprocating engines, and organic Rankine cycles are not discussed further in this chapter.

In addition to the prime movers, a CHP plant typically requires many other components/systems to make a complete CHP plant. The actual requirements depend on the CHP plant itself, but the following are common to many CHP applications:

- Fuel supply system(s)
- Gas compressors
- Combustion air

- Turbine inlet cooling
- Exhaust systems
- Exhaust heat recovery
- Lube oil systems
- Lube oil heat recovery or rejection
- Engine jacket cooling water
- Water treatment systems
- Heat rejection systems such as cooling towers
- Battery or compressed air starting system
- Black start generator/backup power system
- A method of integration of voltage and phase with other electrical supplies
- Plant and engine controls

Heat recovery systems recover waste energy, not used in the prime mover to produce power, to serve thermal loads like building heating, process heating, domestic hot water production, building cooling, or pool heating, for example. In CHP, the most common application is to provide steam, hot water, and/or chilled water for building heating and cooling. These CHP plant systems are discussed later in this chapter and in Chaps. 10 and 11.

Table 3-1 compares and contrasts prime movers in CHP systems. Engineers, facility operators, and owners with a good understanding of equipment considerations and how prime movers integrate into the complete CHP system will find themselves having more productive and efficient conversations on the subject of CHP and how to best implement CHP in buildings and facilities.

Fuel-to-Power Equipment

As discussed, most fuel-to-power equipment burns fuel in a combustion process that converts the chemical energy of the fuel into rotational kinetic energy, which can be transmitted through a shaft to produce electrical power in an electrical generator (fuel cells are the exception). Fuel-to-power prime mover equipment is usually connected to an electrical generator. While the great majority of CHP systems use mechanical energy to drive a generator to produce electricity, other alternatives involving chemical reactions are currently being studied and implemented. Several types of fuel-to-power equipment exist today that can effectively generate power. When a prime mover and generator is a factory combined package, the package is often called an engine-generator-set or “genset.”

As noted, the basic criterion for CHP is that CHP produces both thermal and electrical energy from a single fuel source. In this respect, CHP differs from the typical electrical power generation plant today. The other factor, as described in Chap. 1, is that CHP typically makes more complete use of the energy value of the fuel by beneficially recovering and using heat which would otherwise be wasted.

There are different choices and methods available when developing a CHP system. One basic configuration of a CHP system is the use of an IC reciprocating engine or combustion turbine generator with heat recovery equipment capturing exhaust heat

Technology	Combustion Turbine	Natural Gas Engine	Diesel Engine	Microturbine	Fuel Cell	Steam Turbine
<i>Size (MW)</i>	1–200	0.05–7	0.05–10+	0.025–0.25	0.02–0.4	Any
<i>Electric Efficiency (%)</i>	25–40 (simple) 40–60 (combined)	25–40	30–50	20–30	40–50+	30–42
<i>Heat Rate (Btu/kWh)</i>	8,500–13,600	9,700–13,600	7,000–11,300	11,300–17,000	7,000–8,500	8,100–11,300
<i>Waste Heat Recoverable (Btu/kWh)</i>	3,400–12,000	1,000–5,000	1,000–5,000	15,000	500	NA
<i>Waste Heat Temp for Recovery CHP (°F)</i>	500–1,100	500–1,000	180–900	400–650	140–700	NA
<i>Typical Uses of Heat Recovery</i>	Heat, hot water, LP-HP steam, district heating/cooling	Hot water, LP steam, district heating/cooling	Hot water, LP steam, district heating/cooling	Heat, hot water, LP steam	Hot water, LP-HP [†] steam	LP steam, district heating
<i>Fuels</i>	Natural gas, biogas, propane, distillate oil	Natural gas, biogas, propane	Diesel and residual oil	Natural gas, biogas, propane, distillate oil	H ₂ , natural gas, propane	All
<i>Fuel Pressure Required (psi)</i>	120–500	1–45	<5	40–100	0.5–45	NA
<i>NO_x Emissions (lb/MWh)</i>	0.3–4	2.2–28	3–33	0.4–2.2	<0.02	NA (from the steam turbine itself)
<i>Power Density (ft²/kW)</i>	0.02–0.61	0.22–0.31	0.22	0.15–1.5	0.6–4	<0.1
<i>Typical Online Availability (%)</i>	90–98	92–97	90–95	90–98	>95	Near 100
<i>Time between Overhauls (hours)</i>	30,000–50,000	24,000–60,000	25,000–30,000	5,000–40,000	10,000–40,000	>50,000
<i>Start-up Time*</i>	10 min–1 h	10 s	10 s	60 s	3 h–1 day	1 h–1 day
<i>Noise</i>	Moderate	Moderate to high	Moderate to high	Moderate	Low	Moderate to high

*Note warm up times are significantly longer.

[†]LP stands for low pressure and HP stands for high pressure.

Source: Adapted from U.S. Department of Energy (1999) (Ref. 5).

TABLE 3-1 Comparison of Typical CHP Prime Mover Technology

and heat from the IC engine coolant loop. The IC engine type of system is most often used where the electrical loads are 2 to 3 MW or less, and where the need for thermal heat is low in comparison to the need for electrical power (i.e., a relatively low thermal-electric ratio). Since IC engine prime movers tend to be more fuel efficient than combustion turbines, there is more electrical power and less thermal energy proportionally derived per unit of fuel.

IC engines are available in sizes from less than 50 kW to more than 15 MW. Combustion turbine generators range from approximately 1 MW to well over 100 MW. Combustion turbines require high-pressure gas supply or gas compressors to provide the necessary gas pressure. Combustion turbines typically have higher exhaust temperatures, higher volume exhaust and, as a result, combustion turbine generators are better suited for applications where high temperature recovered heat is required, such as high-pressure steam, or low-pressure high temperature oil. Combustion turbine-based CHP systems also have higher thermal-electric ratios than IC engine-based systems. In addition, since combustion turbines tend to be less thermally efficient in producing electricity, the application favors situations where there are high year-round, 24 hours a day thermal loads and where the cost of piping thermal energy to those loads is relatively low.

Internal combustion engines are better suited for applications which require lower recovered waste heat temperatures, such as hot water or low-pressure steam (typically less than 15 psig). IC engines can be used with lower quality fuels. An example is an IC engine powered on methane gas from a wastewater treatment plant or a garbage landfill. Internal combustion engines require less specialized maintenance, training, and auxiliary equipments than combustion turbine generators.

IC Reciprocating Engines

Engine Types

IC reciprocating engines are machines that translate the linear movement of pistons into the rotational movement of a crankshaft through a combustion process. Combusting fuel heats and expands the fuel-air mixture inside a cylinder which drives the piston. Most of engines today are multicylinder for smoother power delivery. The two basic types of IC reciprocating engines are spark ignition and compression ignition. Each of these engine types is available to operate in either a four- or two-stroke combustion cycle. The strokes of the four-stroke cycle are intake, compression, power, and exhaust. Engines are either naturally aspirated or turbocharged. In naturally aspirated engines, air and fuel are mixed in a carburetor and the intake stroke draws in the fuel-air mixture. A turbocharged engine has a compressor which compresses air and discharges that air into the combustion chamber during the intake stroke. In most cases, only the air is injected by the turbocharger and fuel is directly injected into the combustion chamber eliminating carburetors or external mixing of fuel and air. In either case, a turbocharged engine can deliver more power because there is a greater density of fuel and air in the process.

The two-stroke cycle differs from the four-stroke cycle in that it combines the power and intake strokes into one stroke while the exhaust and compression strokes are combined into a second common stroke. Start-up time for reciprocating engines can be fast, around 10 seconds for diesel-fueled engines. Warm-up times take significantly longer and depend upon the mass of the system. The warm-up time can be reduced if the system

includes a crankcase heater to keep the engine warm. A crankcase heater is considered mandatory for a CHP system serving as an emergency power system.

Reciprocating engines are classified into three speed categories, low, medium, and high speed, that see engine speeds range from 60 to 275 rpm for low-speed engines and 1000 to 3600 rpm for high-speed engines. Spark ignition engine generators are designed to operate on fuels such as natural gas or fuel oils but can burn other fuels. One other fuel is methane fuel derived from decomposition of organic matter as mentioned earlier. In Brazil, engines burn 100 percent alcohol. In the United States, a gasoline-alcohol mixture is sometimes used (see Chap. 25). During World War II, the Japanese powered their auto engines with coking gas derived from heating coal or wood in an airless chamber and driving off gases which were piped to the engine fuel-air intake. In short, almost any gaseous fuel can be burned; however, some fuels will damage the engine and scrubbers/filters may be required to meet engine manufacturer warranty requirements.

Spark ignition engines get their name from the electrical charge, or spark, that is added at the end of the compression stroke that ignites the fuel-air mixture to start the power stroke.

Compression ignition engines differ from spark ignition engines, in that there is no spark added to the air-fuel mixture to start combustion. Instead, the intake air is compressed by the piston's motion inside the cylinder. A compression ignition engine uses very high compression ratio which heats the air in the chamber to a point high enough to ignite the fuel. At the top of the compression stroke fuel is injected into the hot compressed air in the combustion chamber and spontaneous ignition occurs. The heat of combustion develops very high pressure which drives the piston in an expansion stroke. When a compression engine is first started a glow plug is heated by an electric source. Once the engine is running and hot, the glow plug is no longer needed. Compression ignition engines most commonly use diesel fuel (No. 2 oil), but can also be fueled by a wide range of petroleum products (up to No. 6 oil). Compression ignition engines (also referred to as diesel cycle engines) can also be fired with gaseous fuel in combination with liquid fuel, called pilot oil, used as the ignition agent in dual fuel engines. The fuel in a compression cycle engine needs to have a fairly high flash point to prevent ignition until full compression is achieved at the top of the piston stroke.

Turbo- or Supercharger Power Boosters

Both spark ignition and compression ignition engines can be outfitted with turbo- or superchargers to increase power output and, often times, to improve efficiency. As noted above, a turbocharger is a relatively small compressor that is mounted on a common shaft with a small turbine. As hot exhaust gas enters the turbine and expands, the turbine spins, spinning the compressor impeller at the same time. Engine intake air is routed through the compressor to precompress the combustion air, creating a denser air charge to enter the cylinder. A supercharger is another type of compressor that also works to precompress the air; however, it does not rely on exhaust gas to drive the compressor. Instead, superchargers are belt- or gear-driven from the engine's crankshaft, using a small amount of engine output power to yield a greater overall power output. Turbochargers are the most commonly utilized precompression tools in CHP today.

Rich Burn versus Lean Burn Engines

Naturally aspirated engines must have a fuel-air ratio that is high enough to ignite in the engine without additional heat of compression. A "rich" mixture can have too little oxygen for complete combustion and some of the fuel energy is wasted. Also,

a shortage of oxygen results in the formation of carbon monoxide in the exhaust gases (incomplete combustion).

Turbo- or supercharged engines can burn a mixture of fuel and air which has more air. This fuel-air mixture can result in both more energy from the fuel and a cleaner exhaust.

In the past, natural gas engines were operated at an air-fuel ratio that provided the most horsepower for the air consumed. This method of operating an engine is termed *fuel rich* (or *rich burn*), because of the “lambda” or proportion of the operating air-fuel ratio to the chemically correct air-fuel ratio (see below) where all the fuel and oxygen is consumed during combustion is less than 1. The inverse of the fuel-air ratio is the air-fuel ratio. The chemically correct air-fuel ratio for complete combustion is also known as the stoichiometric air-fuel ratio. The equivalence ratio is the ratio of the operating air-fuel ratio to the stoichiometric air-fuel ratio:

$$\lambda = \text{equivalence ratio} = (\text{operating air-fuel ratio})/(\text{stoichiometric air-fuel ratio})$$

Currently, many natural gas engines are operated at a much leaner air-fuel mixture to take advantage of lower emissions and fuel consumption characteristics. A leaner air-fuel mixture ($\lambda > 1.0$) allows for a higher concentration of oxygen in the combustion chamber, more than is required for combustion. Therefore, a higher concentration of oxygen is present in the engine exhaust.

The combustion temperatures in natural gas engines are lower when operating at a fuel-rich air-fuel ratio and rises as the λ approaches 1.0 (stoichiometric air-fuel ratio). As the air-fuel ratio becomes leaner, the combustion temperature again decreases (see Fig. 7-1 in Chap. 7). Table 3-2 summarizes the effect a rich or lean air-fuel ratio relative to the

Atmospheric Pollutant	Rich Air-Fuel Ratio	Lean Air-Fuel Ratio
NO _x	Lower, due to decreased concentration of oxygen molecules to react with nitrogen compounds and the lower combustion temperature	When λ is slightly greater than 1, NO _x is high because of the high concentration of oxygen and high combustion temperatures. NO _x decreases significantly for leaner air-fuel ratios because the combustion temperatures are lower
CO	Much higher, due to decreased concentration of oxygen molecules to react with the fuel molecules, and the resultant incomplete combustion	Lower, due to the high concentration of oxygen to react with the fuel. The CO concentration increases slightly for leaner air-fuel ratios because of the lower combustion temperatures
NMHC	Higher, because of the low concentration of oxygen and total combustion of all the fuel is incomplete and is passed with the exhaust	NMHC rise as λ is greater than 1, when as λ is slightly greater than 1, NMHC is high because of the high concentration of oxygen and high combustion temperatures. NMHC increases slightly for leaner air-fuel ratios because the combustion temperatures are lower

TABLE 3-2 Effects of Air-Fuel Ratio on IC Engine Emissions

stoichiometric air-fuel ratio has on engine emissions. Note that both carbon monoxide (CO) and nonmethane hydrocarbons (NMHC) have their lowest value at an equivalence ratio near 1.0.

In general, except for NMHC depending on the air-fuel ratio, the lean combustion engine provides much lower levels of atmospheric pollutants. The lean combustion engine is sometimes capable of meeting emissions requirements without the aid of exhaust treatment and air-fuel ratio controllers depending on the location of the CHP plant.

Although lean combustion engines offer benefits such as lower pollutant emissions, lean combustion engine's emissions performance degrades significantly to sometimes unacceptable values when they are operated at part load. Therefore, load management and exhaust treatment may also be necessary for lean burn combustion engines. Additionally, lean burn engines may be more temperamental and require more maintenance than naturally aspirated rich burn engines.

Reciprocating engines are cooled by a jacket water cooling system. Jacket water cooling systems are either pump driven, ebullient, or a combination of both. Pump-driven cooling systems tend to operate at lower temperatures than ebullient cooling systems. Ebullient means "with boiling" and such systems use density differences between steam and water in the cooling water to circulate water in the engine. Ebullient cooling systems require operation at fairly high temperatures. The temperature must be high enough for water to begin a phase change within the engine. This type of system is used to produce low-pressure steam (approximately 15 psig) by connecting the jacket water to a tank (steam drum) above the engine where the steam and hot water separate. The tank has a jacket cooling water supply connection on the bottom of the tank to the engine and a heated jacket steam/water return up near the water/steam interface in the tank. Heat in the engine causes steam bubbles to form and the mixture of water and steam bubbles is much lighter than water alone, which results in a pressure difference across the engine jacket causing water circulation. The height of the water level in a tank above the engine determines the temperature and pressure of steam produced. The steam can be used for heating processes or for use in a single-stage absorption chiller (see Chap. 4). Condensate and feed water systems are needed with an ebulliently cooled IC engine CHP system. Ebullient systems require a separate system to cool engine oil.

Size Ranges

IC engine generators are available in a wide range of sizes to meet many applications. Both natural gas and diesel fuel engines can have electrical outputs from 50 kW to 15 MW. Automotive derivative engines supply the lower end of the power production scale, generally less than 10 MW, while the larger engines in the 15 MW and above range are typically derived from marine applications. Various off-road equipments and stationary power engines derived from truck engines provide CHP alternatives between the automotive and marine derivative power output ranges.

Useable Exhaust Temperatures/Useable Heat

As discussed, waste heat in the form of hot water or sometimes in the form of low-pressure steam can be recovered from reciprocating engine jacket manifolds, after-coolers, lubrication systems, and engine exhaust. In terms of temperature, the highest potential is from exhaust gases, then from the engine jacket, and the lowest temperature potential is heat recovery from lube oil cooling systems. Lube oil cooling systems are particularly temperature sensitive due to oil breakdown at high temperature.

The total amount of waste heat from an engine is the total amount of fuel energy input less the energy value of the rotary power produced. Not all the waste energy produced can be usefully recovered. As an example, engine heat loss by radiation to the space is not ordinarily recovered. Also, most CHP systems do not recover heat past the point that the water vapor produced as part of the combustion process (due to oxidation of hydrogen in the fuel) is condensed. Unless the exhaust is specifically designed for condensation, condensation in the exhaust is avoided because, due to the formation of carbonic acid (H_2CO_3), condensate is corrosive and can damage the exhaust system. The latent heat in the water vapor is a significant part of the heat of combustion (around 10 percent in the case of natural gas) and depends on the type of fuel burned. For example, fuel oil derives more energy from carbon, which creates less water vapor than does natural gas. Because the portion of the latent heat of vaporization for water in the fuel heat of combustion is a function of the fuel type and its chemistry, and because most processes do not recover the water vapor energy (i.e., the latent heat of vaporization for water), most engine manufacturers rate their engines in a fuel's lower heating value (LHV). The LHV does not include the latent heat of vaporization for water in the fuel heat of combustion, compared to the higher heating value (HHV), which does include the latent heat of vaporization for water in the fuel heat of combustion. While engine performance may be rated based on the LHV, fuel purchases are typically based on the HHV, and owners, operators and engineers must take these differences into consideration in their calculations.

The amount of waste heat which can be recovered from the IC engine depends on the type of engine, the temperature at which the heat recovery occurs, and on the type and capacity of the heat recovery equipment. In general, a turbocharged engine has more of its waste heat in the exhaust gases than a naturally aspirated engine. The higher the temperature at which beneficial heat recovery must occur, the less energy that can be recovered.

The typical distribution of input fuel energy for a reciprocating engine operating at rated load can be broken down as follows:

1. Shaft power	32%
2. Convection and radiation	3%
3. Rejected in jacket water	32%
4. Rejected into the exhaust	30%
5. Lube oil cooling	3%

The latent heat of vaporization for the water vapor created by combustion of hydrogen is lost in the exhaust gases unless the gases are cooled to a point where the water vapor condenses. Condensing systems can be highly efficient and improve CHP sustainability, but, as noted, the exhaust system must be designed for the corrosive condensate (e.g., constructed of stainless steel). Most of the heat in jacket water and lube oil cooling can be recovered and used. Usual heat recovery practices can recover some 60 to 80 percent or higher of the heat in the exhaust gases depending on various factors including the thermal output temperature, with the highest efficiency achieved when the exhaust gases are cooled to near ambient temperatures.

With respect to the fuel distribution percentages discussed above, it should be noted that the percentages vary with manufacturer, model as well as with engine load.

As noted, the quantity and quality of the heat that can be collected from reciprocating engines per kilowatt of power produced (thermal-electric ratio) is lower than that can be obtained from CTGs which have higher thermal-electric ratios. First, less of the fuel energy is converted to shaft horsepower in a typical CTG versus a typical IC engine meaning more waste heat is available with a CTG. Second, with a CTG, nearly all the waste heat is in the exhaust air stream versus an IC engine. And third, the exhaust gas temperatures are much higher with a CTG than most of the waste heat from a reciprocating engine. Most engine jacket cooling systems operate at around 200°F and offer good opportunity to recover heat in the form of hot water. For many applications, the exhaust heat can be recovered into the coolant loop using an exhaust-to-liquid heat exchanger to provide a single form of heat recovery. As noted above, a few internal combustion engines permit coolant to reach 250°F at above atmospheric pressure and then allow the coolant to flash into low-pressure steam (15 psig) after leaving the engine jacket in an ebullient cooling system.

Heat Rate and Electrical Efficiency

As noted in Chap. 1, heat rate is defined as the amount of input energy required by the prime mover to produce 1 unit of power. CHP heat rate for natural gas-fueled spark ignition engines can range between about 10,000 to almost 14,000 Btu/kWh, while the heat rate for diesel engines can be as low as 7000 Btu/kWh. As shown in Fig. 3-1, the heat rate for spark ignition engines tends to decrease (i.e., the engines become more efficient at producing power) as the rated power output increases (i.e., the engines become more efficient with increased size). Note that a lower heat rate means that less energy is required per kilowatthour produced.

As shown in Fig. 3-2, spark ignition engine electric efficiencies (electric power output divided by fuel input in consistent units) generally increase as the engine's rated power increases. Typical spark ignition engines between 100 and 900 kW have observed electric efficiencies between about 25 and 30 percent based on the HHV. Larger spark

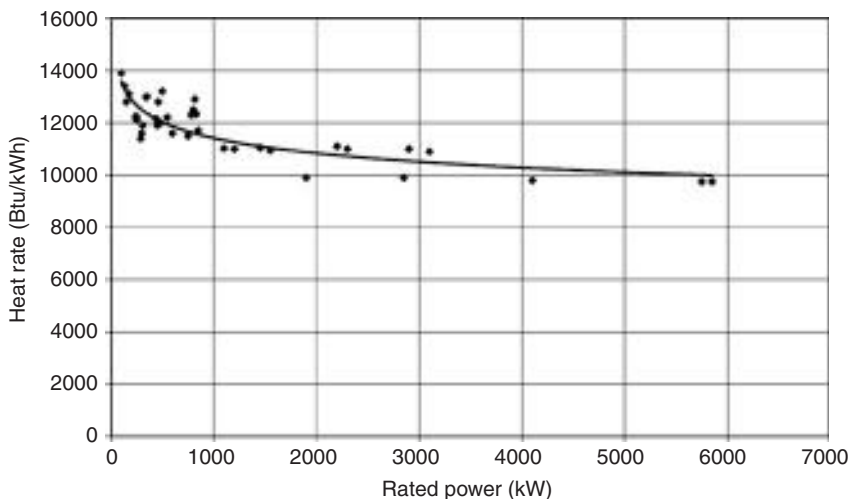


FIGURE 3-1 Heat rate (HHV) of spark ignition engine. [Source: 2008 ASHRAE Handbook: HVAC Systems and Equipment (Ref. 1).]

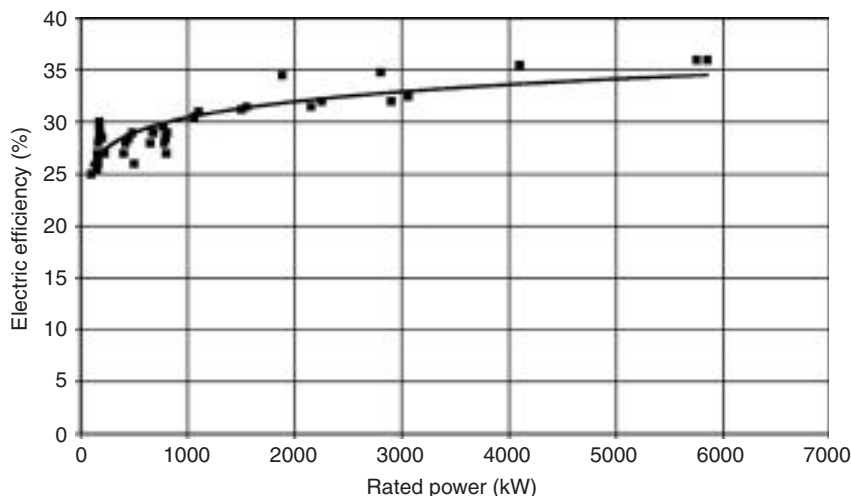


FIGURE 3-2 Efficiency (HHV) of spark ignition engines. [Source: 2008 ASHRAE Handbook: HVAC Systems and Equipment (Ref. 1).]

ignition engines, above 4000 kW electrical output have typical observed efficiencies around 36 percent, based on the HHV. Note that given the electrical efficiency, the heat rate can be easily calculated (or vice versa) as heat rate is equal to the inverse of electric efficiency multiplied by 3413 (the number of Btu per kWh).

Cooling Water Requirements

The heat developed by reciprocating engines of either type (spark ignition or compression ignition) must be rejected to prevent overheating the engine parts, leading to premature engine failure. A coolant loop is used to absorb this heat from the various engine components to ensure that all engine components remain functional. Cooling water with glycol is used as the coolant in many CHP applications to absorb this developed heat and to transfer it to other useful applications. A coolant loop is required for engine components including

- The engine jacket, or block
- Turbochargers
- Aftercoolers
- Lube oil coolers
- Exhaust heat recovery devices

The coolant loop can be the “jacket water system” which transfers heat to beneficial thermal uses and/or to heat rejection (heat dump) to keep the engine cool.

Emissions

Emissions fundamentals and control strategies are discussed in depth in Chap. 7; however, it is important to note that, in almost every CHP reciprocating engine application, some form of emission control technology is often required. These technologies,

including catalytic conversion and selective catalytic reduction (SCR), aim to reduce the amount of pollutants that are emitted into the atmosphere and to minimize the CHP plant's local environmental impact. NO_x , CO, and NMHC are main emissions to be controlled. For rich burn engines, three-way catalyst are typically employed to reduce NO_x , CO, and NMHC emissions to acceptable levels. With lean burn engines, a SCR system is used to reduce NO_x levels; an oxidation catalyst reduces CO and NMHC. With an SCR system, ammonia injection will be required and some form of on-site storage will be needed (often in the form of an aqueous urea solution). All catalysts must be kept at the proper operating temperature to function correctly and not be damaged. If the exhaust temperature into the catalyst is too low, the proper emissions reductions will not take place. Higher than allowable exhaust temperatures can cause damage to expensive catalyst requiring its replacement.

Noise and Vibration

Due to the reciprocating motion of the internal components, IC engines tend to produce significant vibration and noise. The noise includes low-frequency rumble denoted by a continual, loud, thumping sound emanating from the engine block. This noise can be a problem and noise is typically addressed by sound attenuation inside an enclosure (either the building housing the CHP plant or a special dedicated enclosure, or both). Additional noise can occur from improperly positioned or designed air intake and discharge systems and/or inadequately muffled exhaust systems. Positioning exhaust discharges and air louvers and vents away from places where noise will cause problems can reduce some of the observed noise. Not all of the engine noise can be mitigated through these techniques. Installing reciprocating engines in sound-insulated engine rooms is one good way to help mitigate unwanted sound. Engines are usually mounted on vibration isolators to greatly reduce vibration transmission from the engine to surrounding areas. Where vibration is likely to cause problems, an isolated inertia base is often used in addition to vibration isolation on the engine. While a heat recovery heat exchanger will help reduce translated engine noise, an exhaust muffler may also be required. Chapter 10 addresses various design solutions intended to minimize or mitigate unwanted noise and vibration associated with IC reciprocating engines.

Controls

Apart from being able to safely start and stop a reciprocating engine generator set, additional controls are required to protect the mechanical integrity of the engine and installed CHP system. For example, alarm and shutdown controls are required for adverse situations, such as low oil level, low oil pressure, high oil temperature, high coolant temperature, low coolant temperature (to help prevent thermal shock), low coolant level, or inadequate coolant flow. Correct air intake temperature and air mass flow, proper fuel delivery, and correct spark timing (in the case of spark ignition engines) are also important factors in proper engine function.

Engine speed controls are typically designed to keep the engine at a constant rotational speed in order to maintain the correct generator frequency. Often, the generator must stay in phase with either utility power or with another generator (see Chap. 11). Governors are installed on engine generators to regulate fuel delivery and to keep rotational speeds within a narrow design range. However, the engine governor's ability to respond effectively to a changing load condition is a function of the nature and magnitude of the load change. Virtually all governors can maintain steady-state conditions

without any trouble (as measured by the amount of overshoot, undershoot, or offset compared to setpoint), while virtually no governor can handle a large step load change without a change in engine speed, which can cause the generator to trip off-line. Diesel engine generators can typically handle larger step loads than natural gas-fired engine generators, which have a maximum step load of around 25 percent of full generator capacity. Every manufacturer and model has a different maximum allowable step load, and the allowable increase may depend on the percent the generator is loaded at the time of the step load. For example, a 20 percent step load may be permissible at 80 percent load, but not at 5 percent load. Governors also allow for decreased operator input as well as for extended engine life. Overspeed trips are control devices installed on engines that stop fuel flow when rotational speeds increase above safe operating conditions, typically the result of governor failure or some other control failure.

Equipment Life, Operation, and Maintenance

Reciprocating engine equipment life, like with any machine, is a function of its operation and maintenance (O&M), engine operating hours, engine run speed (e.g., low speed versus high speed), and frequency of oil changes and overhauls. All affect the expected useful life of an internal combustion reciprocating engine. Perhaps the most important factor outside of engine rpm is the design, materials, and quality of construction of the prime mover engine.

Regular maintenance, including engine cleaning, scheduled oil changes, and proper water treatment, is important for the successful and efficient operation of a CHP plant. Predictive maintenance needs are possible if instrumentation and/or controls are installed which observe every aspect of engine operation and show any irregularities in day-to-day engine operation. Observed increases in fuel usage, increased heat exchanger approach temperature, and cylinder operating conditions, when trended over time, can be symptomatic of larger problems for operators. When well maintained, including timely overhauls, reciprocating engine generator sets can be expected to operate between 20 and 30 years, or sometimes longer.

Combustion Turbines

Combustion turbines and combustion turbine generators are gaining popularity in CHP installations today, where power requirements are consistent throughout the day and there is consistent use for the relatively larger quantity of high-grade thermal energy year-round. Although the thermodynamics of combustion for turbines and reciprocating engines is similar, the mechanical process is vastly different. In a multi-stage combustion turbine, a multistage air compressor is mounted on a common shaft to a multistage turbine. Outside air is ducted to the compressor, where the pressure and temperature are increased before being delivered to the combustor, where the hot, compressed air is mixed with fuel and ignited, creating high-pressure, high temperature gas that is subsequently expanded in the turbine to provide shaft power. The shaft power is used to drive the generator and to drive the compressor (in some cases the CTG is designed with two turbines, one for each job).

Turbine capacity and efficiency is strongly dependent on the temperature of the air entering the compressor, and, therefore, many combustion turbine systems precool the air entering the CTG compressor. Precooling the combustion turbine inlet air provides more air flow and greater compressor efficiency. Greater turbine inlet air flow can produce more CTG power output. Some turbine inlet air cooling systems use evaporative cooling, since air density is related to dry bulb temperature. Other turbine inlet air cooling systems

use chilled water from absorption chillers driven by recovered steam from the steam turbine generator exhaust. Still other turbine inlet air cooling systems cool the inlet air use chilled water from ice storage with the ice produced by electric power at night when other facility electrical loads are lower. The advantage of ice is that ice can produce lower inlet air temperatures than can be produced with absorption produced chilled water.

Types and Sizes

Combustion turbines are either single-shaft or two-shaft designs and are classified as either aero-derivative or industrial type. Aero-derivative gas turbines for stationary power are adapted from their jet, helicopter, and turboshaft aircraft engine counterparts. This type of combustion turbine is essentially a jet engine that is anchored to a fixed frame. While these turbines are lightweight and thermally efficient, aero-derivative turbines can be more expensive than products designed and built exclusively for stationary applications. Aero-derivative combustion turbines are available from many manufacturers in electrical capacities ranging from about 1 MW up to about 15 MW (although some manufacturers have much larger units) and up to 40 percent simple cycle efficiency (based upon LHV with recuperated turbine and no heat recovery). As previously discussed, the fuel-to-electrical efficiency can be increased by use of waste heat steam to produce more power (combined cycle). Steam generated in a waste heat recovery steam generator (HRSG) located at the turbine discharge can produce more electrical power in a steam turbine generator (STG) or it can be injected into the CTG combustor after the compressor to increase the flow of gases through the turbine, cooling the gases to reduce NO_x and increasing the CTG power produced.

Industrial, or frame, combustion turbines are built for stationary electrical generation and are available in much higher capacities (up to around 500 MW). Industrial combustion turbines are heavier than their aero-derivative cousins as well as typically less efficient. Industrial combustion turbines have maximum simple cycle efficiencies of approximately 36 percent (based upon HHV). As shown in Fig. 3-3 and as discussed

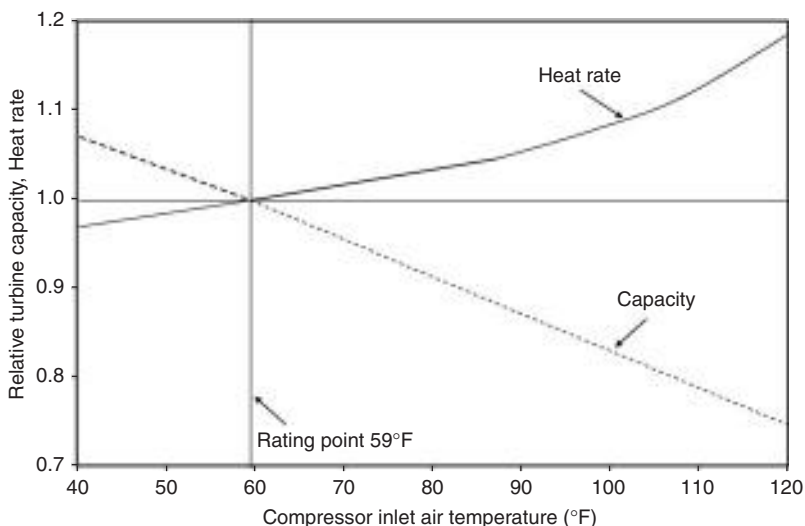


FIGURE 3-3 Relative turbine power output and heat rate versus inlet air temperature. [Source: 2008 ASHRAE Handbook: HVAC Systems and Equipment (Ref. 1).]

above, the heat rate for combustion turbines increases with increased inlet air temperature while, at the same time, power output capacity falls linearly. As a rule of thumb, a 10°F increase in air temperature approximately equates to about a 5 percent decrease in power output. Combustion turbine inlet cooling, as discussed, can be effective in maintaining consistent power output even at higher outside air temperatures.

The amount of inlet pressure loss and combustion turbine backpressure also affects the performance of the combustion turbine generator, and the CTG inlet and outlet pressure drops need to be kept within the turbine manufacturer's allowable limits. An approximate 0.5 percent decrease in power output can be expected for each inch of water column increase in air inlet pressure drop, therefore the design of the combustion turbine air inlet system is critical to successful, sustainable CHP operations.

Heat Rate and Electric Efficiency

Combustion turbine's average fuel-to-electrical shaft efficiencies generally range from about 25 to 40 percent based on the HHV. Larger combustion turbine generators are more efficient than smaller combustion turbine generators. Heat rates vary by manufacturer and model, and in general range from about 8500 to almost 14,000 Btu/kWh.

The remainder of the fuel energy is discharged in the exhaust and a minor amount through radiation or internal coolants in large turbines. A minimum stack exhaust temperature of approximately 300°F is typically required to prevent condensation, unless the exhaust system is specifically designed for exhaust gas condensation, which if not will lead to rapid corrosion of most metal exhaust systems (stainless steel is typically required for condensing exhaust systems). Neutralization of the any condensate before discharging to the sewer is also often required.

Useable Exhaust Temperatures/Useable Heat

Combustion turbines typically run very hot with combustor exhaust gases sometimes exceeding 2300°F. At the turbine exit, exhaust temperatures are reduced down to temperatures between 850 and 1100°F, due to the expansion of the hot gas through the turbine(s). The exhaust temperatures coupled with high exhaust flow rates lead to opportunities for heat recovery and duct firing, which are not feasible with reciprocating engines. In CHP plants, where combustion turbine electric generation efficiency is of utmost importance, regenerators or recuperators can be employed in the exhaust air stream to preheat the compressed air that enters the combustor thereby leading to higher electrical efficiency and slightly decreased fuel consumption.

The combustion turbine exhaust contains a large percentage of excess air; therefore, afterburners/duct burners may be installed in the exhaust to create a supplementary boiler system providing additional steam. Duct burners can be very efficient, reaching an estimated maximum efficiency that exceeds 90 percent.

Cooling Water Requirements

Combustion turbines do not have the same cooling requirements as IC reciprocating engines. Turbines do not have a crankcase or reciprocating parts that require cooling and the only internal cooling typically required is for the oil that lubricates the compressor/turbine shaft bearings and possibly the electric generator.

As noted above, cooling is, however, often utilized to precool the intake air stream. Since the power output of a turbine is decreased by approximately 1/2 percent for each 1°F rise in intake air temperature. Ambient air to the compressor intake is never the same temperature at all times throughout the year. In most cases, there is a significant

difference between a winter night dry bulb temperature and that of a summer day dry bulb temperature. Combustion turbine inlet cooling (CTIC) systems lower or maintain the low intake temperature to ensure the stable output of power at all times. While indirect/direct evaporative cooling is the most common CTIC system type, chilled water coils and direct expansion (DX) refrigerant coils can be used to provide even greater benefit in situations with high outside air temperatures especially those with high humidity. The use of CTIC systems has several benefits including increased power output capacity, lower heat rate, extended turbine life, and system efficiency improvements.

Emissions Control Types

The amount of thermal NO_x generated is directly related (linear function) to the amount of time the hot gases are at flame temperature in the combustor, and related exponentially to the temperature of the flame. The flame temperature is the variable that is more easily controlled and can be adjusted in order to achieve reduced NO_x emissions levels. The flame temperature is a unique function of the equivalence ratio, and, therefore, the rate of NO_x production is likewise a unique function of the equivalence ratio as previously defined.

NO_x production is highest when $\lambda = 1$, and is lowered as the fuel mixture is either richened or leaned ($\lambda < 1$ or $\lambda > 1$, respectively). As the equivalence ratio increases above $\lambda = 1$, so do smoke emissions. As the equivalence ratio decreases below $\lambda = 1$, the carbon monoxide emissions also increase.

The most common emissions control strategy for combustion turbine exhaust is to install selective catalytic reduction (SCR) in the discharges gases. This process requires injecting ammonia into the exhaust air stream. The ammonia reacts with NO_x on the catalyst surface which lowers the NO_x in the exhaust gases. As noted, emissions and emission control methods are discussed further in Chap. 7.

Noise/Vibration

Combustion turbines exhibit noise differently than reciprocating engines, and generate high-frequency noise and vibrations. An operating combustion turbine generator set often sounds similar to a stationary jet airplane and its sound can be loud and uncomfortable to the casual observer. Manufacturers often attenuate this noise by enclosing their turbine generators in sound-insulated enclosures. Locating the CTG in an enclosure reduces sound levels considerably, but will not attenuate the sound completely. Additional sound attenuation equipment is typically installed on turbine generators to further lower noise to acceptable levels. Sound attenuation equipment includes inlet air silencers and exhaust silencers, although, if the CTG exhaust flows through a HRSG and exhaust stack, the HRSG may attenuate the exhaust noise sufficiently without an exhaust silencer.

Vibration levels in combustion turbines are generally low as the rotational nature of the assembly does not include reciprocating parts; however, structural engineers must account for high-frequency vibration in their foundation and housekeeping pad calculations.

Controls

Similarly to internal combustion reciprocating engine generators, CTGs normally have their own stand-alone control system to start and stop safely the CTG based on equipment permissives, and to help ensure the proper operation of the CTG(s) including controlling rotational speed by controlling fuel flow. Of course, as with reciprocating

engines, safety controls are also implemented in case of runaway (or loss of speed control). Also, as with engine generators, a plant control system is required to monitor CHP plant equipment and systems; for example, oil pressures and temperatures, turbine inlet temperature, air inlet and exhaust temperatures, gas pressures, equipment status, and to meter key plant parameters as identified in Chap. 17. Additional supplemental systems (such as CTIC systems) also require controls as their specific operating parameters have consequences on the overall performance of the CTG and the CHP plant as a whole.

Equipment Life, Operation, and Maintenance

Combustion turbines offer life spans of more than 20 years, when well maintained and regularly serviced, and offer large amounts of high-quality (high temperature and pressure) thermal output. Care should be taken to select a combustion turbine or turbines that closely match the baseline electrical load of the building or facility, since the efficiency of these machines at part load can be substantially below that of the full load performance. Combustion turbines are typically designed to operate between 30,000 to 50,000 hours between overhauls. Requirements for preventative and predictive maintenance methods are similar to those with reciprocating engines, even if the actual maintenance is different. In order to limit downtime, many manufacturers have rebuilt replacement turbines that can be used to replace a turbine scheduled for overhaul.

Microturbines

Microturbines are very small combustion turbines, which feature an internal heat recovery heat exchanger called a recuperator, as previously described. In a microturbine, the inlet air is compressed in a radial compressor and then preheated in the recuperator using heat from the turbine exhaust. Heated air from the recuperator is mixed with fuel and ignited in the combustor, and hot combustion gas is then expanded in the expansion and power turbines. The expansion turbine drives the compressor and in single-shaft design drives the generator as well. Two-shaft turbine designs use the turbine's exhaust to power a second turbine (the power turbine) that drives the generator. The power turbine exhaust is then used in the recuperator to preheat the air from the compressor.

Microturbines can be designed to operate on a myriad of fuels, including natural gas, propane, landfill gas, digester gas, sour gases, and liquid fuels such as biodiesel, gasoline, kerosene, and diesel fuel/heating oil, for example. Operating fuel pressures for microturbines may require onboard fuel compressors that are offered as options by most manufacturers.

Microturbines are ideally suited for distributed generation applications due to their flexibility in connection methods, ability to provide stable and extremely reliable power, and low emissions. Types of applications include

- Peak shaving and base load power (grid parallel)
- CHP
- Stand-alone power
- Backup/standby power
- Primary power with grid as backup

In CHP applications, the waste heat from the microturbine is used to produce hot water to heat building(s), to drive absorption cooling, desiccant dehumidification equipment, and to supply other thermal energy needs in a building or industrial process.

Sizes

Microturbines are presently available with electrical outputs varying from about 25 to 250 kW. While this range of electrical outputs is relatively low compared to other prime mover technologies, the smaller footprint of the microturbine makes it ideal for installing them in parallel, creating large banks of microturbine generator sets to create larger power production arrays. This concept offers some benefits over a single, larger combustion turbine generator. One benefit to a microturbine array is that if one machine is out of operation, the entire electrical generation capacity is not lost. A microturbine array also can maintain good efficiency throughout a variable electrical demand as single machines can be shutdown during periods of decreased load, leaving the remaining machines in the array to operate at full load efficiency. One negative aspect with the microturbine array is that a microturbine array will likely be more expensive to construct than a single large prime mover of the same total capacity.

Efficiencies and Heat Rate

Microturbines exhibit shaft efficiencies between 20 and 30 percent, based upon the HHV of fuel burned, which corresponds to a heat rate between 11,300 and 17,000 Btu/kWh.

Because microturbines reduce power output by reducing mass flow and combustion temperature, efficiency at part load can be below that of full-power efficiency. Thermal output ranges from 400 to 650°F which is suitable for supplying heat for a variety of building thermal needs.

Emissions

Low inlet temperatures to microturbines and high fuel-air ratios result in NO_x emissions of less than 10 parts per million (ppm) when operating with natural gas.

Equipment Life, Operation, and Maintenance

Microturbines are relatively new, and, therefore, do not have a long operating history to analyze; however, microturbines can be expected to operate for approximately 10 years when well maintained. As microturbines are packaged into self-contained units, maintenance is usually more limited than with larger custom built CHP systems.

Fuel Cells

Engine or gas turbine-based CHP systems rely on the combustion of fuel to produce high-pressure, high temperature gas that can expand to provide useful work as previously described. The expanded gases are harnessed by the specific equipment, and provide mechanical and thermal energy. In fuel cells, the oxidation process occurs across membranes which cause electron transfer. Fuel cells directly create electric power without a prime mover or generator. The process is usually thought of as a chemical reaction rather than as a combustion process although most typical systems have a fuel and an oxidizer and so the process is technically a combustion process. Combustion is of course a chemical reaction.

Fuel cells are similar in some ways to batteries. With batteries, the chemical reaction that produces the electric power consumes the materials out of which the battery is constructed. As a result, modern batteries, even the rechargeable type, eventually wear out.

The concept of fuel cells has been around for far more than 100 years; however, the first practical use of the technology was made by NASA in the 1960s for use in manned spacecraft providing clean electrical generation and water as a waste product. Over the years, fuel cells have become more practical due to research and development of consumer-focused products, demonstration projects, transportation use, and military hardware use. As shown in Table 3-3, there are several types of fuel cells with somewhat different processes, with different fuel-to-electric efficiencies, and differing waste heat temperatures. Most fuel cells are in the research stage. The fuel cell processes are similar in that fuel (typically hydrogen) and an oxidizer (typically oxygen) are introduced into cells across a membrane separation and the union of oxygen and hydrogen causes ions to flow between the sides of the cells. Many individual cells are combined to form “stacks” which provide power and have water and waste heat as by-products.

Advantages of fuel cells include the fact that they are practically emission free of undesired exhaust gases, are, in some cases, highly efficient, operate at very low noise levels, and that fuel cells are able to respond rapidly to changes in electrical loads. The most common fuel cells (phosphoric acid process) reject heat (the chemical reaction by-product) in the 150 to 200°F range and are about 40 to 55 percent efficient in generating electricity. Other processes have different efficiencies, different temperature heat discharge and different cost per watt. Molten carbon as an example is about 55 percent efficient and discharges heat at high enough temperatures (600 to 650°F) to produce high-pressure steam. In demonstration projects, this steam has been discharged to a steam turbine to add additional electrical power.

Types

Fuel cells differ from simple batteries in that they use a continuous supply of fuel for the chemical reaction, and, provided the fuel supply continues, can operate for extended periods of time. Although many variations exist, the most common type of fuel cell uses hydrogen as the fuel source and the oxygen in air to complete the chemical reaction. The source of the hydrogen is typically natural gas (however, pure hydrogen, propane, and diesel fuel can also be used). The by-product of the chemical reaction is hot water. As hydrogen (the fuel) enters the fuel cell and is mixed with air (containing oxygen), the fuel is oxidized, broken down into protons and electrons. In the proton exchange membrane fuel cell (PEMFC) and phosphoric acid fuel cell (PAFC), positively charged ions move through the electrolyte across a voltage to produce electric power after which the protons and electrons are recombined with oxygen in the air to make hot water. As this water is removed from the fuel cell, more protons are pulled through the electrolyte, resulting in further power production.

Sizes and Availability

Although fuel cells are excellent candidates for CHP, they have one drawback; at this time, the capital cost per installed kilowatt remains high relative to other available CHP prime mover technologies. The availability of other low-cost energy sources, combined with concerns about the exotic materials and developing technologies used in fuel cells, have resulted in limited specific commercial applications. A commercial producer of fuel cells in the United States produces a 200-kW unit that sells for approximately U.S. \$1,000,000. This price is equivalent to U.S. \$5,000 per kilowatt, which is approximately 3 to 4 times the cost of an equivalent IC engine or combustion turbine generator system. Larger fuel cells (1000 kW) are also in development and are expected to sell for U.S.

Fuel Cell Type	Common Electrolyte	Operating Temp	System Output	Electrical Efficiency	CHP Efficiency	Applications	Advantages
Polymer electrolyte membrane (PEM)	Solid organic polymer poly-perfluoro-sulfonic acid	50–100°C 122–212°F	<1 kW– 250 kW	53–58% (transportation) 25–35% (stationary)	70–90% (low-grade waste heat)	Backup power Portable power Small distributed generation Transportation Specialty vehicles	Solid electrolyte reduces corrosion and electrolyte management problems Low temperature Quick start-up
Alkaline (AFC)	Aqueous solution of potassium hydroxide soaked in a matrix	90–100°C 194–212°F	10 kW– 100 kW	60%	>80% (low-grade waste heat)	Military Space	Cathode reaction faster in alkaline electrolyte, leads to higher performance Can use a variety of catalysts
Phosphoric acid (PAFC)	Liquid phosphoric acid soaked in a matrix	150–200°C 302–392°F	50 kW– 1 MW (250 kW module typical)	>40%	>85%	Distributed generation	Higher overall efficiency with CHP Increased tolerance to impurities in hydrogen
Molten carbonate (MCFC)	Liquid solution of lithium, sodium, and/or potassium carbonates, soaked in a matrix	600–700°C 1112–1292°F	<1 kW– 1 MW (250 kW module typical)	45–47%	>80%	Electric utility Large distributed generation	High efficiency Fuel flexibility Can use a variety of catalysts Suitable for CHP
Solid oxide (SOFC)	Yttria stabilized zirconia	600–1000°C 1202–1832°F	<1 kW– 3 MW	35–43%	<90%	Auxiliary power Electric utility Large distributed generation	High efficiency Fuel flexibility Can use a variety of catalysts Solid electrolyte reduces electrolyte management problems Suitable for CHP Hybrid/GT

Source: Department of Energy, December (2008).

TABLE 3-3 Comparison of Fuel Cell Technologies (Ref. 6)

\$1500 to \$2000 per kilowatt sometime in the future. This pricing is closer to what might be considered feasible for installation in a cost-effective CHP plant.

Efficiencies and Heat Rate

Fuel cell electric generation efficiencies range from 40 to more than 50 percent with hydrogen supplied fuel cells (versus hydrocarbon supplied), which corresponds to a heat rate of less than 7000 to about 8500 Btu/kWh.

Equipment Life, Operation, and Maintenance

Although the fuel cells have existed for over 150 years, fuel cells, as noted, are relatively expensive compared to other CHP technologies and largely in a state of research to improve performance and lower costs. As a consequence, there is limited operating history and fuel cells should be thought of as newer technology. Because there is not a long operating history to analyze, it is difficult to comment on the life expectancy of fuel cells. As fuel cells are packaged into self-contained units, maintenance is usually more limited than with larger custom-built CHP systems.

Thermal-to-Power Equipment

Thermal-to-power generating equipment in CHP systems utilizes heat produced by some other process to generate electricity or rotary power. The most common thermal-to-power generating equipment is a steam turbine generator which is driven by either steam produced in a boiler or steam recovered from the waste heat of the fuel-fired prime mover(s) discussed above. When waste heat from a prime mover produces steam for use in a steam turbine, the waste heat/thermal energy produces additional power. Thermal energy can also be used to generate hot water, steam, or chilled water that would have otherwise (in non-CHP systems) required fuel or power. Those systems are discussed in greater detail in Chap. 4.

Steam Turbines

A steam turbine is a mechanical device that converts steam energy (enthalpy) into rotational mechanical power. The rotational power can drive pumps, centrifugal chiller compressors, and other mechanical devices. Steam turbines are often used to drive an electrical power generator.

A steam turbine generator (STG) can make use of the thermal energy produced in a heat recovery steam generator (HRSG) to generate additional power. With a conventional boiler system, to qualify as combined heat and power, boiler produced steam must be used for both heating (and/or thermally driven cooling) and power. Sometimes, this means steam is produced at temperatures and pressures greater than needed for the facility's heating or cooling needs/applications, and the steam is expanded through a STG to the pressure needed for use by the facility. This type of CHP system produces power in direct relation to the thermal load. As a retrofit project, where there is an existing steam boiler and steam distribution system such a system is often very cost-effective to install. The backpressure turbine used is very efficient because all the steam exiting the turbine is beneficially used.

In fact, most of the power produced in the United States is generated by conventional steam turbine generator power plants (fuel is burned in a boiler to produce steam to drive a STG). As noted, when HRSG produced steam is used to produce additional power in a STG, the CHP thermodynamic cycle is known as combined cycle.

Types

Steam turbines are available in two types: axial-flow turbines and radial-flow turbines. Axial-flow steam turbines are those in which high-pressure steam is introduced into the turbine inlet at one end of the turbine and steam flows along the turbine's axis of rotation driving finned (bladed) wheels, or stages, that spin much like a windmill spins under the influence of the wind. Axial-flow steam turbines are further delineated into several basic types, including

- Noncondensing (backpressure) turbines
- Condensing turbines
- Automatic extraction turbines
- Nonautomatic extraction turbines
- Induction (mixed-pressure) turbines
- Induction-extraction turbines

Axial-flow turbines are also defined by the type of stages and blades. The blades can either be impulse or reaction. Impulse blades are fixed to the turbine wheel and undergo rotation from the force of the steam hitting the turbine blades, while reaction blades also undergo rotation due to the nozzle effect as the steam leaves the blades.

Radial-flow steam turbines are dramatically different from their axial-flow counterparts. In a radial-flow steam turbine, high-pressure steam enters the turbine in the center of the turbine impeller and decompresses radially, perpendicular to the turbine's axis of rotation. This drop in steam pressure (and energy) provides the motive force that causes the rotation of the turbine and, thus, the rotation of the shaft driving any mechanical device or generator. Multistage radial-inflow steam turbines are factory prepackaged equipment that include two or more impellers connected through reduction gearing with steam piping installed between stages to transport steam from one stage to the next. Condensate, if any, is removed between stages, since turbines (of all types) operating at high rpm can be severely damaged if subjected to trace water droplets.

A noncondensing backpressure steam turbine's exhaust is under pressure, and is, therefore, called a backpressure turbine. The backpressure can be at any pressure required by the low-pressure secondary steam system, so long as that pressure is lower than the turbine inlet pressure. The greater the pressure difference the more potential for generation of power. Backpressure steam turbines provide an energy efficient method to reduce steam pressures compared to using pressure reducing valves which lose much of the steam energy. Most of the energy difference between the steam entering and leaving a backpressure turbine is converted to shaft horsepower so the process is quite efficient. For example, if a steam boiler can produce 200-psig steam and only 60 psig is needed for distribution, a backpressure steam turbine can be used to generate power operating on the energy difference between 200- and 60-psig steam. The power produced is a function of the steam pressure difference across the backpressure turbine and the steam flow. Steam flow is related to the thermal loads served and usually varies.

Another application may serve part of steam plant needs where different pressures are needed. As an example, a hospital may need 150-psi steam for sterilizers and 15-psi steam for domestic water and space heating, absorption cooling, and other process. When the steam is produced by waste heat recovery from a prime mover like a combustion turbine the application is similar. Steam is generated at pressures higher than

needed for the thermal loads served. The steam pressure is then reduced through a backpressure turbine to the pressure needed to serve the thermal loads.

A condensing steam turbine is a steam turbine that exhausts into a condenser where the exhausted steam is condensed. The condenser will be in a vacuum allowing much more enthalpy to be obtained from each pound of steam, making the steam turbine thermodynamic process much more efficient. Most condensers are water cooled but some condensers are air cooled. Condensing turbines are the usual choice in commercial electrical power plants since the only need is for electrical power. A condensing turbine provides more rotational power for the steam available but most of the energy is lost in condensing. With a backpressure turbine, the condensing occurs in serving the thermal loads and is therefore beneficial. The overall efficiency in serving both power and thermal need is therefore much greater for a backpressure turbine. Of course, a power plant that does not serve a thermal load is not a CHP plant.

Extraction condensing turbines allow steam to be removed from the turbine at any reduced pressure, including multiple reduced pressures. So, for example, steam could enter the STG at 200 psig and a portion of the steam could be extracted at 100 psig to feed the medium pressure steam system, a second extraction port could also bleed off steam at 15 psig for use in the low-pressure steam system, and the remaining steam would drive the turbine to produce useful work as it expands through the rest of the turbine. Since the steam bleed off serves beneficial thermal needs, such a plant is a CHP plant.

The existence of multiple steam turbine types offers mechanical engineers several options to consider when analyzing and designing the most efficient CHP plants. Steam turbine exhaust, when reduced in both pressure and temperature, can be used to supply heat exchangers, absorption chillers, pumps, or other equipments that are designed to operate with steam and that are installed in place of electrically driven equipments.

Size Range

Steam turbines are commonly available in practically any size with some units installed in power generation plants exceeding 100 MW. Steam turbines, since there is no combustion process, have no environmental impacts as do combustion turbines. Steam turbines are likely to be available to make use of CHP produced steam of any quantity, and combustion turbine exhaust duct firing can very efficiently increase the steam production in a combined CTG CHP system.

Electrical Efficiency Range

Steam turbine thermodynamic efficiencies are directly related to the efficiency of the Carnot cycle; therefore, the temperature of the heat source and the temperature of the heat sink set the maximum possible theoretical efficiency. The higher the steam temperature and the colder the condenser water, the higher the theoretical thermodynamic efficiency. Due to irreversibility (entropy), real systems will be less efficient than that predicted by the theoretical Carnot cycle. The efficiency of the turbine design at converting the energy of the steam into shaft energy is also an important factor. Steam turbines of high-quality construction can have isentropic efficiencies as high as 90 percent. Note, the isentropic efficiency is the efficiency of the steam turbine to convert steam energy into shaft power, and is not the same as overall thermodynamic cycle efficiency, which is much lower. To achieve high thermodynamic cycle efficiency, commercial power plants have boilers able to produce very high-pressure steam (often 1000 psig or more)

and superheat the steam. On the other end of the process, the condenser produces as much vacuum as possible, which is a function of the condensing temperature. Some very large plants draw cold ocean or deep lake water. Still most of the steam energy is in the phase change from vapor to liquid and is thus only partially available to a condensing steam turbine.

Noise/Vibration

Steam turbines, like combustion turbines, experience high-frequency noise and rotational vibrations. Noise from a steam turbine is generally around 85 dBA or less, which requires hearing protection when spending an extended time near the equipment. Noise from steam flow in pipes and the operation of pumps may actually be of greater concern.

Controls

Controls for steam turbines are relatively simple and involve controlling the steam flow to match the load, as well as protecting the STG from adverse operating conditions such as loss of lube oil pressure. Starting systems for steam turbines can be as simple as an actuator that is commanded or programmed to open a steam valve and to close the valve to stop the turbine's operation. Governor systems are used to control the rotational speed of a steam turbine to ensure the consistent quality of the power generated as well as to stop the steam in the event of loss of control. Most turbines have automatic turbine trips and a manual emergency trip, for example, on loss of lube oil pressure.

Equipment Life, Operation, and Maintenance

The useful life expectancy for steam turbines depends on the number of run hours, maintenance practices, and feedwater (steam) quality. Well-maintained steam turbines operated with steam generated from good quality water can potentially have a life expectancy exceeding 30 years.

While steam turbines, themselves have very high availability rates (typically 99 percent), steam turbines can be off-line for various other reasons including, but not limited to, boiler or HRSG outages, CHP fuel delivery issues, boiler feed pump outages, and piping leaks, for example. Steam turbines also must be off-line for regularly scheduled maintenance. Overhauls and internal inspections may require turbines to be off-line for between 150 and 350 hours every 18 to 36 months. As with reciprocating engines and combustion turbine generators, good predictive maintenance can lead to reductions in steam turbine generator outages.

CHP Prime Mover Comparisons

Reciprocating engines, gas combustion turbines, fuel cells, and steam turbines all have various advantages and disadvantages when compared to one another. This section compares the characteristics of the various prime movers available for installation in CHP plants.

Electrical Output and Electric Efficiency

The electrical output of the various prime mover technologies ranges from a few kilowatts with the microturbine to hundreds of megawatts that can be delivered by a steam turbine.

The electric efficiency (total electrical output divided by the total energy input energy) of the different technologies ranges from as low as 20 percent with the micro-turbine to over 50 percent with the best fuel cells. The natural gas reciprocating engine has electrical efficiencies ranging from 25 to 45 percent and power output ranging from 50 kW to 5 MW. The CTG has efficiencies ranging from 25 to 40 percent with a simple cycle and 40 to 60 percent with a combined cycle based on the HHV of the fuel. CTG power output typically ranges from 3 to 200 MW, though some manufacturers are producing units with power output as low as 1 MW or as high as 1000 MW.

Heat Recovery Potentials

Different CHP technologies have different heat recovery potentials. Some CHP technologies may produce low temperature hot water (LTHW) generation (less than 250°F), low-pressure steam production (15 psig or less), or medium-pressure steam. Some heat recovery systems are a part of the equipment served. For example, an exhaust gas-fired absorption chiller-boiler, which directly intakes the exhaust from the prime mover and uses the hot exhaust gases directly to drive the absorption process and also to produce hot water for other uses. Another occasional thermal use is direct heating or drying, which can be highly efficient as exhaust gas transfers its energy as it cools to ambient temperature. In some industrial applications, the exhaust from a gas turbine is directed to a process such as drying agricultural products or wood. This application beneficially uses the waste heat without an intermediate recovery process. Such applications are also extremely cost-effective.

LTHW is typically recovered from IC reciprocating engines, although low-pressure steam (less than 30 psig) can be obtained from high temperature engine exhaust. Medium-pressure steam (up to about 250 psig) is typically recovered from a HRSG that uses the CTG exhaust as a heat source. Fuel cells generate LTHW (about 180°F depending upon the fuel cell technology), which can be used for hydronic heating or domestic hot water production.

CTG generally have higher thermal-electric ratios and generate substantially more heat than do IC engines.

The useable temperature of the recovered heat varies. Some applications can use cooling tower water from a steam turbine plant to heat agricultural processes, fish farms, or air drying using heat at 80 to 90°F. On the high end, a duct-fired combustion turbine may recover heat from 1100°F exhaust.

Fuels and Fuel Pressures

As discussed, CHP systems can be designed to operate on myriad fuels including, but not limited to, natural gas, diesel fuel, landfill gas, digester gas, propane, wood or agricultural waste, and so on. As an example, a large power generation plant in California burns walnut husks. In Oregon, CHP plants burn wood waste in sawmills to drive steam turbines for power and use the waste heat to dry lumber. However, the most commonly utilized fuel in CHP systems is natural gas. Natural gas is widely available through local utilities and is rarely subject to interruption in service. When considering the use of natural gas, or any other fuel, the engineer must ensure that the selected prime mover equipment is able to operate with that fuel source. CTGs and microturbines can be designed to operate on fuels including natural gas, biogas, propane, and distillate oil. Natural gas and diesel IC engines, although similar in mechanical function, are designed to operate on different fuels. Natural gas IC engines can be designed to

operate on natural gas, biogas, and propane, while diesel IC engines can be designed to operate on diesel fuel (fuel oil No. 2), biodiesel, or residual oil. Fuel cells can be designed to operate on natural gas, propane, or pure hydrogen gas (H_2). CHP plant installations that include equipment involving the use of dirty fuels, like digester gas, require additional fuel-treatment equipment as this fuel requires drying and cleaning before it can be used in combustion engines.

The fuel pressure required to operate fuel-to-power prime mover equipment in CHP plants varies from between 0.5 and 45 psig for fuel cells to between 120 and 500 psig for CTGs. Natural gas IC engines are designed to operate on low-pressure gas. CHP plant prime mover equipment installations that require high-pressure fuel, including CTGs and microturbines, require gas compression equipment to increase the pressure of the utility-delivered fuel to the required pressure.

NO_x Emissions

Emissions characteristics are important to consider in CHP plant prime mover selections. Permitted allowable limits vary widely depending on where the CHP system is installed. As discussed in Chap. 12, any proposed project must work closely with the air quality regulation agencies and permitting an installation is sometimes a challenge. Untreated NO_x emission levels vary from very high, more than 30 lb/MWh for diesel engines, to almost nonexistent, below 0.02 lb of NO_x per megawatt-hour for fuel cells. Natural gas IC engines have NO_x emission levels in a range of 2 to 30 lb/MWh. NO_x emission levels for CTGs and microturbines vary between about 0.3 to 4 and 0.4 to 2.2 lb/MWh, respectively.

Power Density

The amount of area needed for a CHP plant is a major consideration. Knowing the power density (kW/ft² or kW/m²), that is, how much area is needed for the plant can help engineers estimate the CHP plant square footage that will be required for a calculated facility or building electrical load. The footprint for CHP plant fuel-to-power prime mover equipment installations does not vary widely between all systems considered. CTG and microturbine energy footprints are small, varying from about 0.2 to 0.6 ft²/kW and 0.15 to 1.5 ft²/kW, respectively. IC reciprocating engines can take more room than CTG for the same power output, and energy footprints for natural gas and diesel engines varying from about 0.2 to 0.3 ft²/kW. Fuel cell installations can have some of the largest energy footprints of all CHP plant fuel-to-power equipment at up to 4 ft²/kW. Of course, the balance of plant can require extensive area.

STG energy footprints are noted to be extremely low, typically less than 0.1 ft²/kW; however, it should be noted that STGs represent the thermal-to-power classification of CHP prime mover equipment and additional square-footage considerations must account for the steam producing equipment that is installed to power the thermal-to-power equipment.

Online Availability and Time between Overhauls

Electric power or thermal production capability is often only as good as the availability of the installed CHP plant prime mover equipment's ability to consistently operate to meet the facility electric and thermal loads. All of the noted fuel-to-power prime mover equipment has online availability between 90 and 98 percent, while the noted

thermal-to-power prime mover, the STG, has nearly 100 percent online availability. Availability is a key issue in considering a CHP plant. First, there must be backup system for use when the plant is down if the loads served are essential. If the backup is utility power, there often will be large backup charges, and any energy charges for power used during an outage will likely depend on when the demand is made on the utility. Obviously, CHP plants with multiple prime movers are less impacted by down time because other prime mover(s) should be available when one is being serviced. The right combination of equipment and when service occurs can largely eliminate down time, but no system will ever achieve 100 percent availability. Some maintain that the probability of failure is directly proportional to the negative impact of such failure.

Overhauls involve the deconstruction of major components of the prime mover equipment for the purposes of rehabilitation and/or reconstruction. Often times, equipment manufacturers have backup/replacement equipment available at their factories or service centers that can be installed at the CHP plant in place of the off-line equipment to limit to CHP plant's down time. It is recommended that prime mover equipment be regularly overhauled at consistent intervals to ensure that the CHP plant operates consistently and efficiently. CTGs are typically operated between 30,000 to 50,000 hours between overhauls, which is notably different than their microturbine counterparts, which are typically operated between 5000 and 40,000 hours between overhauls. IC engines are recommended to operate between 24,000 and 60,000 hours between overhauls. Fuel cells are recommended to operate between 10,000 and 40,000 hours. STGs can operate over 50,000 hours between overhauls; however, operating hours are dependent on the cleanliness and quality of the steam used to operate the machines.

Start-Up Time

CHP plant prime mover equipment start-up times should be considered when evaluating electric and thermal load profiles and selecting prime mover equipment to serve the electric and thermal loads. Start-up times vary greatly between all different types of CHP prime movers; from 10 seconds for diesel engines, 60 seconds for microturbines, and 10 minutes to several hours for CTGs. Some prime mover equipment may take even longer to start-up, from 3 hours to up to 2 days for fuel cells and from 1 hour to 1 day for some STGs. While steam turbine generators start quickly, significant time may be required to bring boiler and steam distribution pipes to a proper operation point. It should be noted that although IC engines have very fast start-up times, time required to properly warm up the plant will be significantly longer, especially if crankcase heaters are not in use.

Noise

The noise produced by the various technologies ranges from low enough so that no enclosure is required to high enough so that both an engine enclosure and a building enclosure are required. IC reciprocating engines tend to exhibit more low-frequency higher amplitude linear vibrations than CTGs and STGs, which tend to exhibit higher-frequency noise and vibration. Microturbines share the same type of noise characteristics as CTGs, only to a lesser degree due to their relatively smaller sizes; however, noise is increased when multiple units are arrayed and are operated at the same time. Fuel cells produce the least noise of any of the CHP technologies. The high-pitched noise of a steam turbine is far easier to attenuate than the rumble of an IC engine.

CHP Plant System Requirements

The type of CHP prime mover and the type of thermal production and uses employed at a CHP plant will determine the support systems required. For a CTG, the following typical systems will be required:

- Combustion-air system: louvers, ducting, air filters, turbine inlet cooling, inlet air silencer
- High-pressure gas system: gas compressors
- Low-pressure gas system: pressure reducing valves
- Turbine exhaust system: ducting, duct burners, superheater, HRSG, emission control system, CEMS (continuous emissions monitoring system)
- Electric power generator distribution system: substations, switchgear, motor control centers, protections
- Lube oil system: lube oil cooler, lube oil pump, day tanks
- Fire protection
- Chemical storage and emergency showers

For a CTG CHP system using a HRSG, the following typical systems will also be required:

- Main steam system: nonreturn valve, pressure reducing valves, steam traps to remove condensate
- Condensate system: condensate receiver(s), condensate pumps, deaerating feed tank
- Feedwater system: feedwater pumps, feedwater control station (feedwater control valves)

Emission control systems typically have support subsystems, such as ammonia/urea storage and delivery. For an IC reciprocating engine CHP plant, the following typical systems will be required:

- Combustion-air system: louvers, ducting, air filters, inlet air silencer
- Low-pressure gas system: pressure reducing valves
- Engine exhaust system: piping, heat recovery hot water generator, emission control system, CEMS
- Electric power generator distribution system: substations, switchgear, motor control centers, protection devices (see Chap. 11)
- Jacket water system: jacket water pumps, expansion tank, radiator, heat exchangers
- Hot water supply and return system: hot water pumps, heat exchangers, coils, control valves
- Lube oil system: lube oil cooler, lube oil pump (if needed or not supplied on the engine), day tanks

If a chiller plant is to be part of the CHP plant, the following additional systems will likely be required:

- Chilled water supply and return: chilled water pumps, distribution system, coils, control valves, chemical treatment
- Condenser water supply and return system: cooling towers, condenser water pumps, chemical treatment

Auxiliary systems can include

- Compressed air
- Backup fuel oil storage
- Makeup water
- Treated water: deionized/reverse osmosis (DI/RO)
- Fire protection

It is the responsibility of the CHP design engineer to understand and evaluate the different fuel-to-power prime movers available in the market versus what will best serve the facility (see further chapters). Each prime mover option has various thermal options (see Chap. 4), and the type of prime mover, generated thermal quality, and thermal uses incorporated into the CHP plant will determine the plant systems required. The design engineer should be familiar with each system listed above (Chap. 10 provides additional information regarding design decisions).

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Thermal Design for CHP

Gearoid Foley

This chapter discusses the issues surrounding the thermal aspects of CHP planning and design, waste heat recovery, and the application of the resultant recovered energy to meet facility requirements. The profitable use of the thermal output from a CHP plant is essential to realizing its economic potential. As illustrated in Fig. 4-1, while the revenue from offset electric purchases typically represents 80 percent of the revenue stream, the thermal output typically represents the entire profit margin. This advantage cannot be fully realized unless the CHP system's thermal component is properly designed and its output matches the facility needs 12 months of the year. This chapter will help the reader understand the steps involved in optimizing CHP design to meet a facility's energy needs and therefore maintain high load factor.

Thermal Design for CHP Systems

To implement sustainable CHP, the planning and design process needs to work to maximize the operational savings of the system while minimizing the cost of the project. A good way to attain both these objectives is to design for the maximum electric and thermal load factor achievable. This means that the resultant CHP system will fully utilize the purchased equipment to offset energy from other sources and it also means that costs were not incurred for equipment that is not used. In order to achieve maximum load factor the design process should emphasize matching the facility thermal loads first and then selecting a prime mover (e.g., engine generator or combustion turbine) to meet these requirements. In this way, a thermal first design approach leads to high load factor which in turn leads to a successful project.

This philosophy is based on a couple of basic principles as follows; firstly, it is relatively easy to apply electricity to a facility as it is generally all at a common frequency (e.g., 60 Hz) alternating current; however, the thermal energy used by a building or facility takes many forms including steam at various pressures, high temperature hot water, low temperature hot water, chilled water, refrigeration, hot air, and so on. In many cases, the design will need to incorporate more than one form of thermal energy from the same system. Secondly, load factor is typically more important than efficiency as spending capital resources on high efficiency equipment when the load is not available to meet the equipment output is usually wasted money.

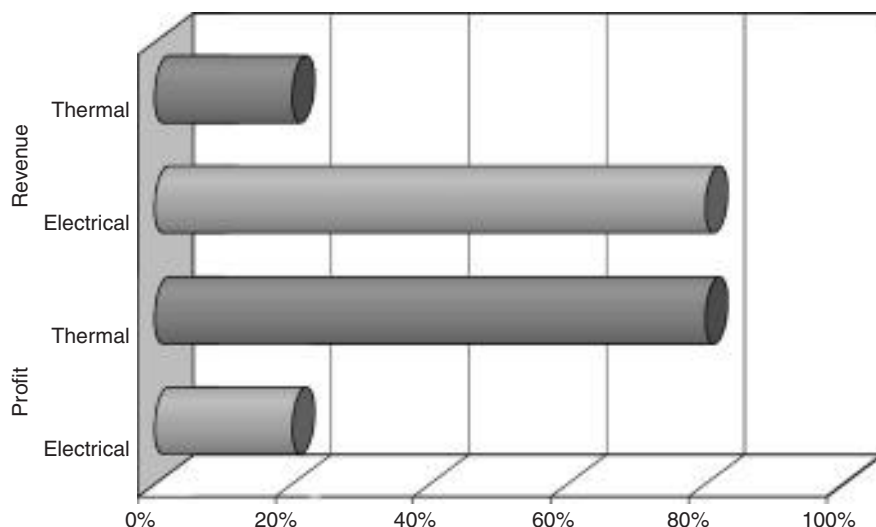


FIGURE 4-1 Thermal contribution to CHP economics. (Courtesy of Integrated CHP Systems Corporation.)

Conventional wisdom would lead to selection of a generator based on electric load profile, then adding thermal equipment based on maximizing system efficiency and then trying to fit the thermal output to the building. This design approach has led to many CHP systems that simply do not meet efficiency or economic expectations as the thermal output is not properly synced with the building resulting in poor load factor. CHP planning experience and design wisdom tells us that it is better to select the thermal components of the system based on the building or facility's thermal loads first, then to select a generator based on thermal output and then to fit the electric output to the building. This of course needs to be done with close regard to the building electric load profile and the process is an iterative one that must result in high load factor for both the electric and thermal outputs of the system.

Load Factor versus Efficiency

It is important to understand the difference between CHP system efficiency and specific equipment efficiency. In most cases, CHP system efficiency is calculated based on the sum of the generator electric output plus the useful thermal energy recovered from the engine generator divided by the fuel input in consistent units:

$$\text{CHP efficiency} = (\text{power out} + \text{useful heat recovered}) / \text{fuel input}$$

Therefore, the more thermal energy recovered, the higher the CHP system efficiency.

Additionally, the typical goal of CHP design is to meet the facility needs—not exceed them. A CHP plant can have multiple options on thermal conversion equipment offering multiple outputs for the same input. It is not always optimal to choose equipment offering the highest possible output. For example, a CHP system can be configured to provide either 75 tons from a single-stage absorber or 100 tons from a

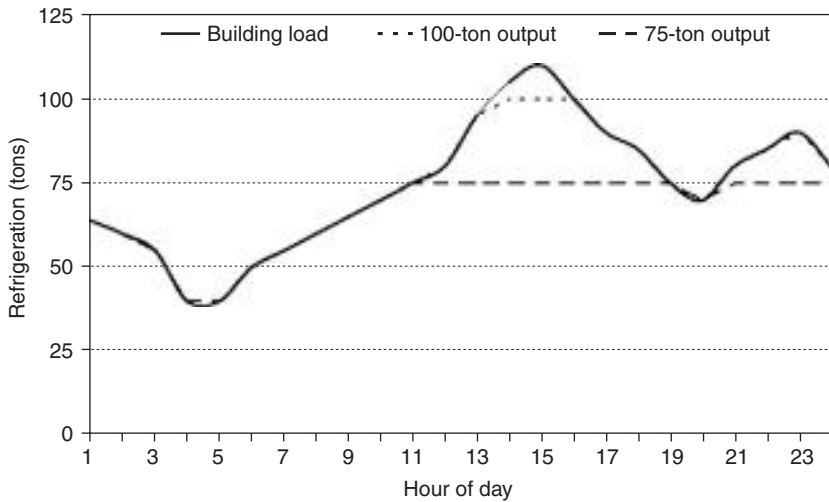


FIGURE 4-2 Load factor example for cooling application. (Courtesy of Integrated CHP Systems Corporation.)

hybrid single/double effect absorber for the same given thermal energy input. As illustrated in Fig. 4-2, the load factor based on the facility load curve is 89 percent for the 75-ton chiller and only 74 percent for a 100-ton chiller, resulting in a higher CHP system efficiency rating for the 75-ton system. As the building load drops below 100 tons, the higher efficiency chiller is forced to bypass heat input and needs to add parasitic load to dump this heat. The less efficient chiller requires all the heat recovered from the engine down to 75 tons and will continue to require more heat through the entire load range for a higher annual CHP system efficiency.

From a capital cost point of view, the 100-ton unit has 33 percent more capacity (and cost) but only produces 10 percent more useful output for the application. The lower cost of the single-stage chiller combined with its simpler maintenance requirements will likely make it the better choice for the example given.

It should be noted that high efficiency is of course a positive aspect in CHP design, but only if the higher output can be applied during the full operational schedule of the system. This is a key element in the success of the thermal first design approach.

Thermal-Electric Ratio

In order to easily match the thermal and electric output of a CHP system with the thermal and electric loads of a building, we need to define a point of reference for both. This reference point is called the thermal-electric ratio (T/E ratio) which is defined for both heating and cooling.

The heating T/E ratio (T/E_H) for a CHP system is typically expressed in terms of the heating output in thousands of Btu per hour (MBH) divided by the power output in kilowatts as follows:

$$T/E_H = \text{thermal output (MBH)}/\text{power output (kW)}$$

For a CHP system with an electric output of 1000 kW that can also provide 4000 MBH of heat output, the T/E_H ratio is 4 MBH/kW.

The cooling T/E ratio (T/E_c) for a CHP system is expressed in terms of the cooling output in refrigeration tons divided by the power output in kilowatts as follows:

$$T/E_c = \text{thermal output (tons)}/\text{power output (kW)}$$

For a CHP system with an electric output of 1000 kW that can also provide 250 tons of cooling, the T/E_c ratio is 0.25 ton/kW.

The above examples are typical for a reciprocating engine-based CHP system with jacket and exhaust heat recovered to provide water heating which can be used to drive a single-stage absorption chiller for cooling. If we need to alter the T/E ratio, it is possible to configure the same engine to recover exhaust only and use a higher efficiency two-stage chiller for cooling. This configuration would still provide 1000 kW, but would have a T/E_H of 2 MBH/kW and a T/E_c of 0.2 ton/kW. The same 1000 kW engine can also be configured to recover the jacket heat only and use a single-stage absorber for cooling to provide a T/E_H of 2 MBH/kW and a T/E_c of 0.13 ton/kW.

As discussed in Chap. 3, combustion turbine-based CHP systems that have more of the fuel energy converted to thermal output will have higher heating and cooling T/E ratios. In addition, the thermal output can be recovered as high-pressure steam (e.g., 125 psig) allowing the use of higher efficiency two-stage absorbers or steam turbine chillers to further boost the cooling T/E ratio. For a typical 5-MW combustion turbine recovering the exhaust to generate steam for heating or to drive a high efficiency chiller, the T/E_H is 5.5 MBH/kW and the T/E_c is 0.6 ton/kW. The same CHP configuration using a duct burner to double thermal output will have a T/E_H of 11 MBH/kW and the T/E_c of 1.2 tons/kW. If we replace the high efficiency chillers with a single-stage steam absorption chiller, the system will have a T/E_H of 5.5 MBH/kW and a T/E_c of 0.35 ton/kW.

These examples serve to illustrate that defining a specific thermal load does not necessarily restrict either the choice or size or the prime mover. This is also a key element in properly applying the thermal first design approach.

Building Loads

For maximum load factor, the CHP system should in general be designed to address the facility minimum or base thermal and electric loads. It will often be necessary to combine more than one thermal load in order to maximize the system load factor such that the CHP system will be able to provide heating in winter and cooling in summer. The system should also be able to provide part heating and part cooling load simultaneously so that high load factor can be maintained through the shoulder seasons (spring and fall). Based on the above discussion on thermal electric ratios, it is apparent that we can vary the heating and cooling T/E ratios independently without having to alter the power output. Assessing all the building thermal needs as well as the power needs will help provide us with the optimal configuration for the CHP system without necessarily restricting choice of the power generator size or technology. In fact, it is essential to properly assess the year round thermal needs of the facility in order to be able to optimize the CHP system design.

A highly significant factor in determining and serving the available facility loads to be addressed by a CHP system is the availability of a thermal distribution system. In order for the thermal energy to be “useful” to the facility, the thermal energy must be capable of being distributed. While a new distribution system can be incorporated into

the CHP design, the cost of such a system often makes the project economically unfeasible (unless the thermal distribution systems are installed as part of new building or facility). Therefore, together with identifying the actual facility loads, a determination must be made on how those loads will be connected to the CHP system. Loads that cannot be connected or are prohibitively expensive to connect cannot be considered in the load evaluation. The connection point for the thermal distribution system will also be a significant factor in the actual location of the CHP plant. If no room exists in or close to the connection point then the costs to bring the thermal output to this location must also be figured into the economic evaluation.

Heat Recovery Options and Design

The available options and design of the heat recovery system are dependent on two factors: (1) the type and quality of thermal energy required to meet the facility needs and (2) the type of power generator used. As with CHP design in general, the type and quality of thermal energy used by the building should be considered first so that maximum load factor can be achieved. This is especially important when retrofitting existing buildings as this factor is already predetermined. The types of thermal energy available are typically high- or low-pressure steam, high or low temperature hot water, chilled water, refrigeration, dehumidification, or hot air. The quality relates to the temperature and pressure of the media being used by the facility.

The type of power generator used also impacts the design and options for heat recovery. Reciprocating engines generate hot water as well as exhaust heat, while fuel cells generate low volumes of high temperature exhaust. Nonrecuperated combustion turbines generate high volumes of high temperature exhaust, while recuperated turbines generate similar volumes of exhaust energy but at considerably lower temperatures.

The total heat recoverable from an engine is a function of the media flow rate, its specific gravity, specific heat, and the temperature differential across the heat recovery device. This can be expressed as follows:

$$\text{Heat recovered} = \text{flow rate} \times \text{specific gravity} \times \text{specific heat} \\ \times (\text{inlet temp} - \text{outlet temp})$$

Generally, the media is either exhaust or water with no or various amounts of glycol additive. The media, its flow, specific gravity, specific heat, and temperature to the heat recovery device are all functions of the type and performance of the prime mover. The outlet temperature from the heat recovery device is a function of its design as well as the type and quality of heat product required by the facility.

For exhaust-driven heat recovery devices, the temperature of the thermal product (i.e., steam or hot water) is inversely proportional to the amount of heat energy that can be recovered. This means that as the product temperature increases, the outlet temperature of the heat recovery device increases resulting in a reduced temperature differential and therefore a lower amount of heat recovered. In general, the exit temperature from the heat recovery device should be no less than 250°F and more typically should be above 300°F to avoid condensation and the associated formation of acid in the exhaust stack. The higher temperature design basis also allows more flexibility to operate the system at part load without forming condensate in the stack.

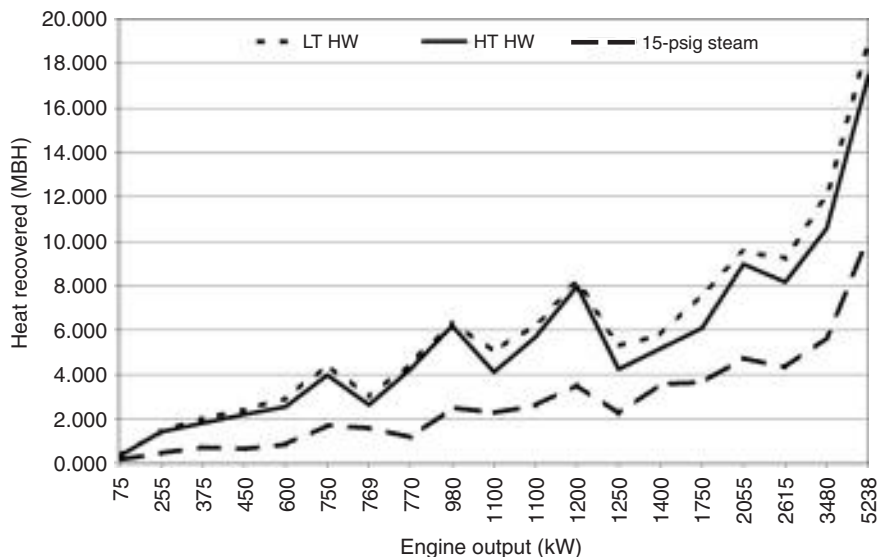


FIGURE 4-3 Heat recovery versus heat quality for various reciprocating engines. (Courtesy of Integrated CHP Systems Corporation.)

For reciprocating engine-based systems, the thermal product quality required by the building can have a dramatic effect on heat recovery. Figure 4-3 gives the heat recovery potential for a variety of reciprocating engines based on the quality of thermal product required. For example, if a facility requires 15 psig or higher-pressure steam or over 240°F hot water, then most engines will not be able to incorporate the jacket loop into the heat recovery process resulting in the inability to recover approximately 50 percent of the waste heat available.

For engines whose thermal output is in the form of exhaust only such as combustion turbines and some fuel cells, the main parameter for calculating the heat recovery potential is product quality requirements. Reciprocating engines present a particular difficulty as illustrated above in providing two distinctly different forms of thermal energy—hot water/glycol through the various engine cooling loops and high temperature exhaust from the engine stack. While each thermal output can be recovered separately, it is often more economically efficient to recover both outputs into a single stream. This is done by passing the engine coolant after it leaves the block through an air-to-liquid heat exchanger and recovering the exhaust energy into the coolant loop, resulting in an increase in temperature. This is especially true for smaller reciprocating engines where the jacket coolant loop represents a higher portion of the thermal output than the exhaust stream and the cost of exhaust heat recovery is unreasonable for such small volumes. As depicted in Fig. 4-4, the combined electric and thermal efficiency for reciprocating engines is fairly constant for all but the smallest engines. This figure also demonstrates the potential to obtain up to 80 percent fuel efficiency from CHP systems when all potential heat output is recovered. As the engines get bigger, electric efficiency increases while the thermal efficiency decreases. The efficiencies depicted in Fig. 4-4 are based on the higher

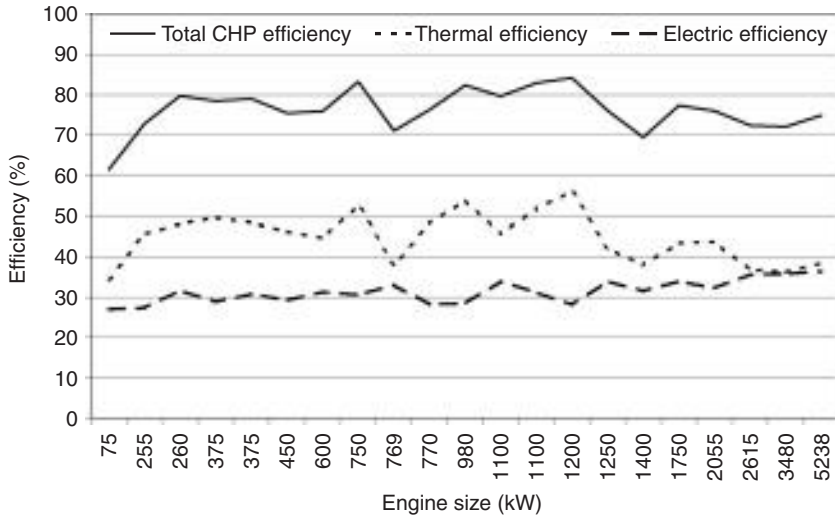


FIGURE 4-4 Reciprocating engine energy output. (Courtesy of Integrated CHP Systems Corporation.)

heating value of natural gas. In addition, as engine sizes increase, the portion of the total thermal output contained in the exhaust stream grows. In addition, lean burn engines generally also have a higher portion of their thermal output in the exhaust loop. For large lean burn engines, over 1 MW, separate exhaust heat recovery can be considered, while for smaller engines and especially smaller rich burn engines, heat recovery is generally best done by blending the exhaust energy into the coolant loop as described above.

Another factor that must be considered in the thermal design is the prime mover operating point through the year. If the engine is base loaded throughout the operating schedule then this is less important but if there are times when the engine needs to be turned down then this will have an effect on heat recovery volume and quality and must be considered. Figure 4-5 demonstrates the thermal quality or temperature recovered from a reciprocating engine when operated at 250 and 150 kW. As can be seen the thermal quality is significantly lower at the lower operating condition—198°F at 150 kW versus 205°F at 250 kW. While the volume of heat recovery will remain roughly linear with engine output/fuel input, the degradation in temperature can have the effect of further reducing output from a thermal conversion device that was designed for full load operating conditions.

Heat Recovery Devices

Depending on the type of prime mover used, there are generally a number of options on the type of heat recovery device that can be applied. For heat transmitted out of the prime mover into hydronic loops, the available energy can be transferred to a secondary hydronic loop or air using simple heat exchangers. The approach or differential between the product outlet temperature and the heat recovery loop return temperature will determine the size and cost of the heat exchanger. As the approach

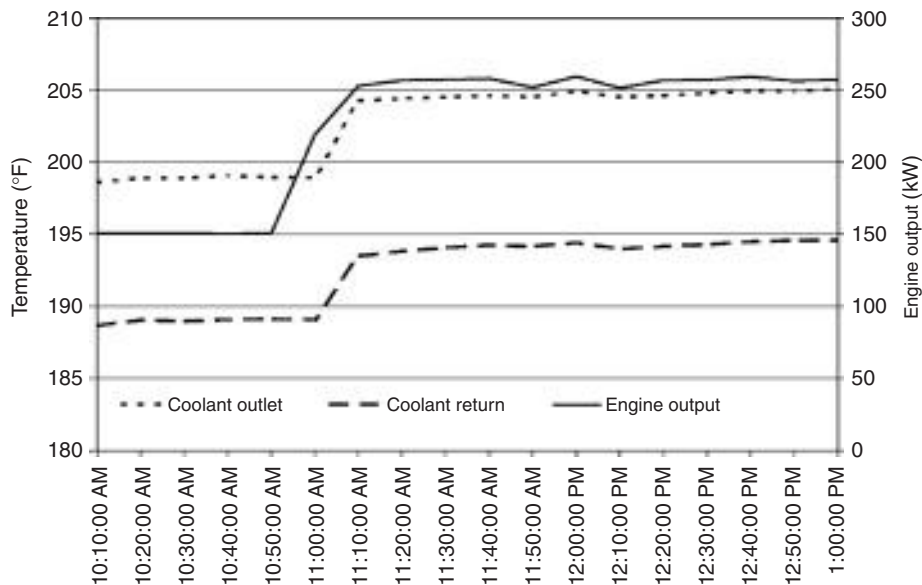


FIGURE 4-5 Coolant temperature versus engine output. (Courtesy of Integrated CHP Systems Corporation.)

temperature is reduced, the size and cost of the heat exchanger increase significantly as more surface area is required to transfer the same amount of heat with a smaller temperature differential.

For exhaust-based systems that produce hot water or steam, heat recovery devices include water tube or fire tube boilers (often called heat recovery steam generators or HRSG when used to produce steam) and coil type water heaters. Exhaust heat can also be recovered through gas-to-air heat exchangers or in some cases used directly in drying or heating processes. Boilers can be used to produce hot water or various steam pressures to meet the facility heating needs as well as supply energy to thermally driven chillers.

In some cases, the heat recovery system can be built into the thermal conversion device as in the case of hot water absorbers where the heat recovery loop can be connected to the absorber without the need for an intermediary heat exchanger. Exhaust-fired absorbers have recently become available where the high temperature exhaust from an engine can be used directly by the chiller without the need first to convert the exhaust energy to hot water or steam. In these cases, care needs to be taken to ensure precise control of the exhaust inlet flow to avoid crystallization in the absorber, especially when operating at varying load.

In the case of combustion turbines, the exhaust gases contain sufficient oxygen to allow the efficient combustion of natural gas. If a high T/E ratio is desired, the turbine heat recovery boiler may be fitted with a supplemental burner or duct burner to allow more thermal energy to be added to the system at very little additional cost. These supplemental burners operate at very high efficiencies and provide additional flexibility in meeting facility thermal needs.

Thermal Technologies

For many CHP designs, there is a need to provide some form of thermal energy other than heating, in order to maintain high annual load factor or to meet process needs. For the purposes of this discussion, thermal technologies are considered to be devices that are driven by heat and used to provide some form of useful thermal energy other than heat. Thermal technologies generally use the products of the heat recovery system but in some cases they can use the thermal energy generated by the prime mover directly and thereby combining the heat recovery function into the thermal technology. These thermal technologies can be broken into various equipment groups as follows:

- Absorption chillers
- Adsorption chillers
- Steam turbine–driven chillers
- Desiccant dehumidifiers

We will review each of these technologies briefly with respect to their applicability to CHP design. Further information on the operation and particular characteristics for each technology is available from a variety of sources.

Absorption Chillers

There are multiple forms of absorption chillers available using a variety of refrigerants and configurations. In order to understand the basics we will take the most common form of absorber available—the hot water–fired single-stage lithium bromide absorption (LiBr) chiller.

The operating principle is based on the relationship between the absolute pressure and boiling point of water. At atmospheric pressure (14.7 psia) pure water boils at 212°F. As the pressure increases the boiling point is raised and as the pressure reduces the boiling point is lowered. In a LiBr absorber, water is used as the refrigerant and is sprayed on the tube bundles which contain building chilled water at 54°F, for example. The absolute pressure in the absorbers evaporator section is reduced to approximately 0.1 psia. At this pressure, water will boil at approximately 40°F. The building chilled water inside the evaporator tubes provides sufficient heat to cause the refrigerant water to boil. This change in phase of the refrigerant requires energy which is supplied by the building chilled water. The energy given up by the building chilled water is in the form of sensible energy resulting in a drop in temperature, thus providing a cooling effect.

A water/lithium bromide solution is used in conjunction with the refrigerant water due to its hygroscopic properties and high boiling point. Once the refrigerant vaporizes to cause the cooling effect it will begin to increase the pressure within the system and must be removed in order to continue the process. LiBr is sprayed in the “absorber section” of the chiller (hence the name) where it absorbs the refrigerant (water) vapor to prevent an increase in pressure. The resultant dilute (or weak) LiBr is then directed to the chiller’s generator section where the weak solution is heated using thermal energy such as hot water. The absolute pressure in the generator is considerably higher than in the evaporator to increase the boiling point and allow higher temperatures in this area. The water vapor is driven off to regenerate or

strengthen the solution, which is then returned to the absorber section of the chiller to continue the absorption process. The water vapor that is driven off in the generator is directed to the condenser section where it is condensed and returned to the evaporator to continue the cooling process.

The absorption principle was discovered in the late eighteenth century and was commercialized early the following century using ammonia (NH_3) and water as the refrigerant/absorbent pair. These devices were used in the American Civil War for food storage related refrigeration and were applied for space conditioning early in the twentieth century. In the later twentieth century two-stage absorbers were developed and water was used as the refrigerant with lithium bromide (LiBr) being used as the absorbent as an alternate to the ammonia/water pair. Absorbers encompass a variety of forms based on thermal energy sources as follows:

- Single- and two-stage hot water fired LiBr
- Single- and two-stage steam fired LiBr
- Two-stage exhaust-fired LiBr
- Single- and two-stage hot water- or steam-fired NH_3
- Two-stage exhaust-fired NH_3
- Hybrid single-/two-stage LiBr and NH_3

While LiBr absorbers now form the mainstream choice for space conditioning, ammonia absorbers are still the choice for low temperature applications as well as having the ability to be configured as thermally driven heat pumps that can significantly increase the volume of hot water generated from a CHP system. LiBr systems operate under high vacuum, while ammonia systems operate at high pressure. The choice of chiller will generally depend on the particular application requirements with ammonia absorption units being the only option for refrigeration. Absorption efficiency is expressed as a coefficient of performance (COP) which is calculated as the cooling output divided by the energy input in consistent units.

Single-stage absorbers generally have a full load COP of approximately 0.7 when fired with 15-psig steam or 240°F hot water at ARI conditions. Two-stage absorbers have a full load COP of approximately 1.2 when fired with 120-psig steam or 350°F hot water at ARI conditions. ARI conditions refer to the American Refrigeration Institute Standard 560 for absorption chillers, which measures performance based on providing 44°F chilled water supply based on 54°F chilled water return using 4 gallons per minute (gpm) of 85°F condenser water per ton of cooling. This essentially means that for every 1,000,000 Btu/h of heat input under the above conditions, a single-stage absorber will generate 58.3 tons and a two-stage chiller will generate 100 tons, based on a COP of 0.7 and 1.2, respectively. Since CHP systems are generally designed to address the base load and therefore operate at or close to full load through most operating hours, we are not so concerned with part load efficiencies. The part load COP can be significantly higher due mainly to the lower condenser water temperatures associated with the lower ambient temperatures concurrent with lower loads. The full load COP can be increased by lowering the condenser water temperature but there is limited capacity to achieve this due to the danger of crystallization of the LiBr solution. This is particularly true for two-stage absorbers which operate at high solution

concentrations, while single-stage absorbers have somewhat better capabilities to use low condenser water temperatures due to the lower solution concentrations found in these chillers.

The choice to use hot water or steam to fire the absorber is based on the site's need to have hot water or steam available for other purposes and generally does not impact the chiller cost, efficiency, or operation. In applications that generate high-pressure steam (greater than 100 psig) or high temperature hot water (greater than 300°F), the higher efficient two-stage absorbers are generally preferred. It should be noted, however, that the choice of efficiency should be subject to the availability of load as mentioned in the earlier section on thermal design. For applications that require high-pressure steam but do not have high cooling loads, then the single-effect chiller can provide the cooling required at a significantly lower capital cost than two-stage absorption units.

For many CHP systems, the heat recovered from the prime mover may not be at the nominal pressures or temperatures described above. This is particularly true for reciprocating engines where the heat recovery loop is subject to the engine jacket design parameters. In many of these instances, the hot water available will be below the nominal absorber rating of 240°F. Most hot water absorbers can still perform at lower than nominal hot water temperatures although at derated conditions. The most significant impact of lowering the hot water temperature below nominal is the change in cooling capacity associated rather than efficiency. Figure 4-6 illustrates the reductions in both capacity and COP for a standard design single-stage hot water-fired absorber as the hot water inlet temperature is reduced. From the graph we can determine that the capacity factor for a standard chiller is 70 percent at a hot water inlet temperature of 210°F.

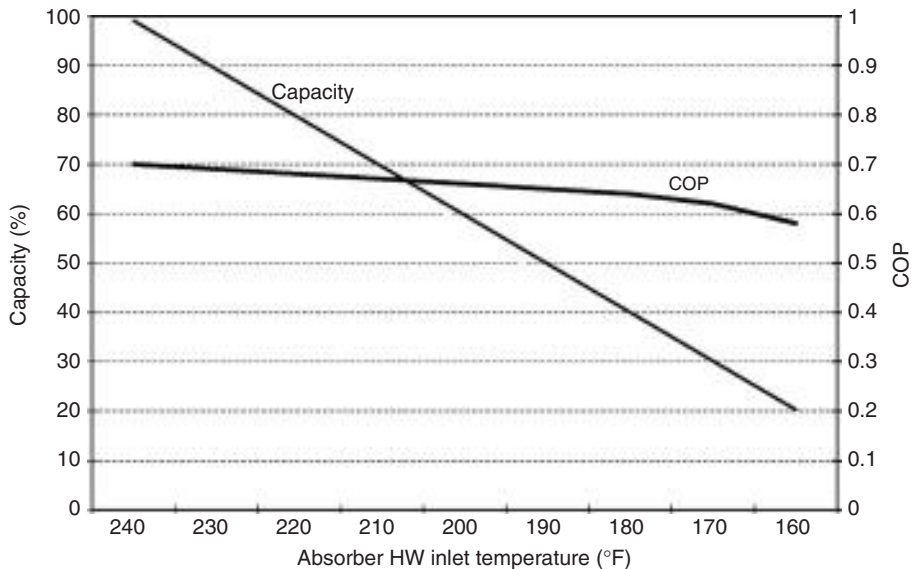


FIGURE 4-6 Single-stage absorber capacity and efficiency versus hot water temperature. (Courtesy of Integrated CHP Systems Corporation.)

This means that a 100 nominal ton chiller will only provide 70 tons at 210°F inlet hot water temperature. Therefore in order to meet the full cooling capacity from a system capable of producing 100 tons the system will require a chiller sized at 100 tons divided by 70 percent or 143 nominal tons. This adds to the cost, size, and weight of the chiller and needs to be factored into the economic and engineering evaluation. As the inlet temperature to the absorber (outlet temperature from the heat recovery device) goes below 200°F the capacity loss becomes too large for many applications to remain viable. Note that the efficiency remains fairly consistent through most of the temperature range and is much less of a concern.

Many absorption manufacturers now provide “low temperature” versions of their single-stage design to specifically address this issue. These low temperature hot water absorbers provide enhanced tube surface, higher heat transfer surface area, multiple pass circuits for longer residence time and other alterations to improve capacity resulting in a more cost-effective absorption chiller that will also provide improved performance at part load conditions. It should be noted that these low temperature chillers do cost more per ton and are larger and heavier than “standard” design chillers.

If cooling from an internal combustion (IC) engine-based CHP system is a critical factor, then it is recommended to select an engine that can offer the highest hot water temperatures within the size range required to help reduce the cost impact of the cooling system.

Hybrid single-/two-stage absorbers are also available for reciprocating engine-based CHP systems. These chillers take the exhaust energy directly into the first stage of the absorption generator and the jacket coolant loop into the second stage of the generator. The system can generate cooling in the first stage at a COP of 1.2 and in the second stage at 0.7 for a combined COP of approximately 0.95 assuming a generator with 50 percent of its thermal output in the form of exhaust heat and 50 percent in the jacket coolant loop. The hybrid chiller offers a good option for larger reciprocating engine-based systems where the additional cooling output gain over single-stage units can be base loaded. Hybrid absorption chillers also incorporate the heat recovery device into the chiller for reduced heat recovery space and cost requirements. However, hybrid chillers are more expensive and require more sophisticated control and maintenance than either the single- or two-stage “indirect-fired” absorption systems.

While single-stage absorbers have a lower efficiency than either the two-stage or hybrid chillers, they are also cheaper and simpler to operate and maintain and are less sensitive to variations in system operation. This can be a significant advantage when applying CHP systems to facilities that do not have full-time qualified facility maintenance personnel.

Adsorption Chillers

Adsorbers combine absorption and desiccant systems. They employ water as the refrigerant using the same pressure/temperature relationship described for absorption. During the cooling process, 54°F return chilled water from the building passes through tubes in the evaporator section, which is held at an absolute pressure of approximately 0.1 psia. Refrigerant water is sprayed on surface of these tubes and is evaporated resulting in a drop in temperature of the building chilled water inside the tubes. Instead of using a chemical absorption reaction as with lithium bromide, the adsorber uses a solid desiccant such as silica gel, which adsorbs the water vapor to allow the cooling process to continue.

Once the desiccant material has adsorbed all the water vapor it can handle, it needs to be regenerated before continuing the process. The adsorber had two “evaporator/adsorber” chambers and operates as a batch system providing cooling in one chamber while hot water is used to regenerate the desiccant in the other chamber. The water vapor that is driven out of the desiccant during the regeneration process is passed through a condenser section where it is condensed and returned to the evaporator. Once the cooling cycle is complete the system interrupts the flows and switches from cooling to regeneration in the first chamber and begins cooling in the second chamber.

The adsorber is driven by hot water and has a significantly lower operating temperature range than a single-stage LiBr absorber. The adsorber can use hot water at down to 150°F but will have a significant capacity and efficiency derating at this temperature. For adsorption the maximum temperature to the chiller is more restrictive than absorption at 195°F. The adsorber COP ranges from 0.5 to 0.7 depending on hot water temperature input and is rated at similar conditions to the ARI Standard 560 conditions used for absorption.

While adsorbers have the advantage of being able to use relatively low temperature hot water, they are considerably more expensive per ton and are larger than comparably sized absorbers. Adsorbers require chilled water and hot water storage tanks, since it is a batch process and also require significantly higher condenser water flow rates of approximately 8 gpm/ton by comparison to absorbers which require typically 3.5 to 5 gpm/ton. It should be noted that single-stage hot water fired absorbers do require increasing flows of condenser water when trying to operate on low temperature hot water. The requirement for a hot water storage tank does provide for stable operation through engine heat recovery variations and the adsorber itself will continue to operate at lower part load on an engine beyond the capability of an absorber. This is particularly useful for designs incorporating multiple engine modules and a fixed flow hot water header. In this scenario, the adsorber will be able to maintain a higher cooling output at a lower power output from the CHP system than absorber. However, as stated above, a typical CHP system generally should not have significant drop in power output.

As the condenser water and hot water share the same tube bundle in the adsorber, a heat exchanger with associated circulating pump will be required between the cooling tower water and the adsorber. This adds to the project cost as well as the size of the cooling tower.

Steam Turbine Chillers

Steam turbine-driven chillers are essentially the same as electric centrifugal vapor compression chillers except that the electric motor is replaced with a steam turbine drive. In an effort to maximize the efficiency of these units, steam turbine chillers are generally designed with condensing turbines and are provided with a steam condenser as well as a refrigerant condenser. These chillers are driven by high-pressure steam from 100 to 600 psig and are typically rated at 125 psig.

Steam turbine chillers have a full load COP of 1.2 at ARI conditions which is comparable to two-stage absorption. They differ from two-stage absorbers in being able to use low condenser water temperatures even at full load for significant efficiency gains at full load during off-design ambient conditions. This is a considerable advantage for the steam turbine in CHP applications where the chiller is base loaded and the steam

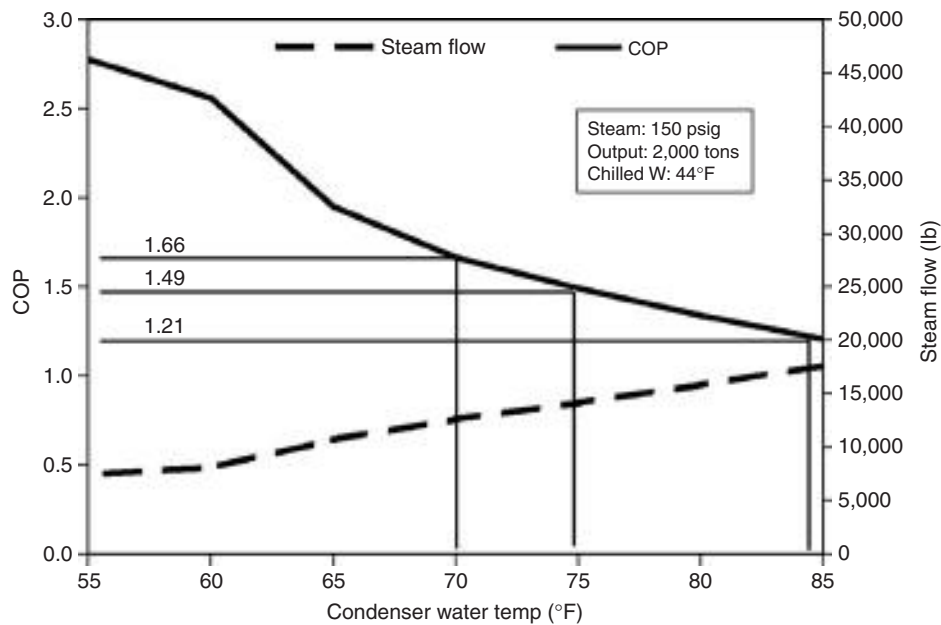


FIGURE 4-7 Steam turbine efficiency versus condenser water temperature. (Courtesy of Integrated CHP Systems Corporation.)

saved due to increased chiller efficiency can be used for other purposes. Figure 4-7 provides a graph of efficiency versus condenser water temperature for a 2000-ton steam turbine chiller using 150-psig steam at full load. At full load and a condenser water temperature of 70°F, the steam turbine chiller will operate at a COP of over 1.6.

The steam turbine chillers also have relatively low condenser water flow requirements compared to absorbers at 3.5 gpm/ton which are similar to electric chillers. In addition, the turbine chiller can produce low chilled water temperatures well below 40°F without suffering significant capacity or efficiency losses.

Steam turbine chillers are available sizes ranging from 700 to 2500 tons, are generally more expensive per ton in smaller sizes and only become cost competitive with absorption above 1000 tons. If the condenser is located above the evaporator these chillers have approximately the same footprint as an electric chiller and smaller than an absorber. The ability to provide low temperature chilled water and to take advantage of low ambient conditions to increase efficiency make them suitable for larger distributed energy type CHP applications.

Desiccant Dehumidifiers

Desiccant systems are thermally driven air conditioners that remove the moisture from an air stream by absorbing or adsorbing the water into a desiccant material. They come in two types—liquid and solid—with each type having slightly different characteristics. Liquid desiccant systems typically use a lithium chloride (LiCl) and water solution to absorb the water in an air stream thereby to dry the air. The diluted LiCl solution is then directed to a hot water-driven regeneration process, where the water is expelled and the

resultant “strong” solution is returned to the air stream to collect more moisture. Solid desiccants generally use a wheel impregnated with an adsorbent material such as silica gel to remove the moisture from an air stream. As the wheel becomes saturated it is rotated into the regenerator section where thermal energy is used to desorb the material and prepare it for further moisture removal.

Desiccants are used in humid regions for fresh air treatment where they remove the latent load and work in conjunction with chillers to meet the building total cooling needs. They are also applicable in buildings requiring low dew points such as refrigerated warehouses and supermarkets, where large internal humidity loads need to be removed such as natatoriums. Desiccants are generally available in relatively small sizes compared to thermally driven chillers and are therefore suitable for application with small CHP systems.

For desiccants, the COP varies from 0.5 to 0.7 based on the enthalpy of the water removed divided by the energy input with newer versions of the liquid desiccant system having the higher COP. Desiccants are air side systems and as such are also easier to apply in smaller applications where hydronic thermal distribution system are not available. Hot water-driven liquid desiccant systems generally require lower activation temperatures at approximately 180°F whereas hot water-driven solid desiccants require up to 240°F for regeneration. In CHP applications using exhaust heat recovery, the desiccant system can be used as a bottoming-cycle using the exhaust after the primary thermal conversion steam boiler or chiller. Where hot water is recovered from the primary thermal conversion device, the exhaust temperature will generally be too low to regenerate the desiccant.

Liquid desiccant units require a cooling tower to remove the heat of absorption from the system. Solid desiccants are also exothermic devices but do not require a cooling tower and instead pass the process latent to sensible heat gain into the space. Generally this sensible heat gain is removed using a downstream sensible cooling coil as the desiccant system typically works in conjunction with a chiller to handle both latent and sensible loads. Desiccant systems are denominated in terms of cubic feet of air that pass through the conditioning section, but when denominated in tons at maximum moisture removal capacity are comparable to absorption on a cost-per-ton basis.

Technology Comparison

When designing a CHP system, the selection of a thermal conversion device will depend on the type and size of addressable facility loads and the type of prime mover to be employed. As discussed above, the thermal-electric ratio or T/E ratio is the primary characteristic used to ensure high load factor when matching a facility with a CHP configuration. CHP design does not limit the selection of a prime mover when the thermal output has been selected as each prime mover will have multiple T/E ratios depending on the heat recovery equipment and the thermal technology selected. From this perspective Table 4-1 outlines the different prime movers available together with typical T/E ratios when coupled with various thermally driven technologies.

The T/E ratios given in Table 4-1 represent the an average value for each of the CHP configurations described and can vary depending on the specific characteristics of the prime mover selected. T/E ratios for turbines can be doubled or tripled with the addition of supplemental firing providing additional flexibility for these configurations.

Prime Mover	Thermal Technology	T/E Ratio
Reciprocating engine	Hot water generator	4 MBH/kW
	Steam generator	2 MBH/kW
	Single-stage absorption	0.25 ton/kW
	Two-stage absorption	0.20 ton/kW
	Hybrid absorption	0.30 ton/kW
	Adsorber	0.25 ton/kW
	Steam turbine chiller	0.20 ton/kW
	Desiccant	0.20 ton/kW
Combustion turbine	Hot water/steam generator	5 MBH/kW
	Single-stage absorption	0.35 ton/kW
	Two-stage absorption	0.6 ton/kW
	Steam turbine chiller	0.6 ton/kW
Microturbine	Hot water generator	7 MBH/kW
	Two-stage absorption	0.5 ton/kW
	Desiccant	0.3 ton/kW
Fuel cell	Single-stage absorption	0.15 ton/kW
	Two-stage absorption	0.20 ton/kW

Source: Courtesy of Integrated CHP Systems Corporation.

TABLE 4-1 CHP Technology Comparison Chart

Load Characterization and Optimization

As discussed, a CHP system should be sized to meet the addressable base loads of the facility and in many cases the system will need to be configured to meet multiple thermal loads (e.g., heating and cooling) in order to maintain high load factor throughout the year. It is essential to characterize the thermal loads by form (e.g., steam or hot water) and quality (e.g., 125 psig) as well as to accurately identify the requirements throughout the operation period. Where possible, a load duration curve should be developed to determine the appropriate size for the thermal system as a first step. This curve traces the number of hours in the year that the load is at or above a specific load point. Figure 4-8 is an example of a cooling load duration curve for a facility with a year-round cooling load and a peak load of 5000 tons.

For this example, we will assume that the facility only has a cooling load available and the system is intended to run all year. From the load duration curve we can see the CHP system would only achieve a 100 percent load factor if it were sized at 1000 tons. At 2000 tons, the system would have approximately a 50 percent load factor which typically would not be viable from an economic standpoint. If this same facility has a base load of 2000 kW after the CHP cooling system has been applied then the facility cooling T/E ratio is 0.5 ton/kW. It is important to recalculate the electric base load after the cooling system has been applied, since this will have the effect of reducing the base

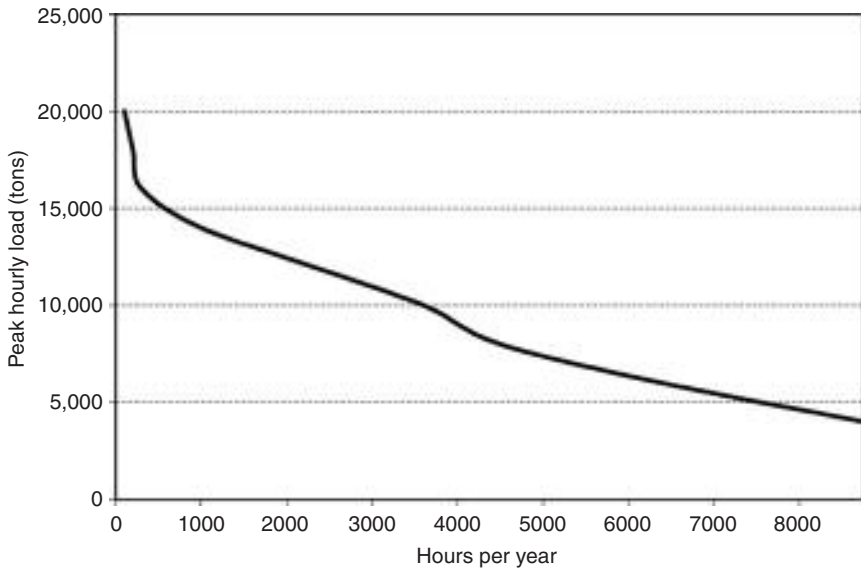


FIGURE 4-8 Cooling load duration curve. (Courtesy of Integrated CHP Systems Corporation.)

electric load if the chillers were based on electric motor drive vapor compressors. This example can apply any CHP configuration with a T/E_c ratio value of 0.5 ton/kW such as a combustion turbine.

If the facility does have a heating need, then we can combine the heating and cooling loads to increase the thermal output of the system. In this case we would only need to address the cooling loads during the summer which would then provide us with a base load of over 2000 tons for a 100 percent load factor during the 4000 hours of the summer. Now the T/E_c ratio becomes 1 ton/kW so we could consider a combustion turbine with duct burner to meet this load.

While most facilities have 15-minute interval data available for power usage, most do not have similar data available for thermal loads. Considering the investment required to install a CHP plant, it is advisable to install flow meters and temperature sensors to measure and record thermal loads at hourly intervals if these devices are not already installed. The cost to accurately measure thermal loads is far outweighed by the cost savings from a well-designed CHP plant.

In addition to calculating the base load for the system, we also need to understand the type and quality of the load. As noted, thermal loads take many forms from steam, hot water, and hot air for heating to chilled water, refrigeration, and dehumidification for cooling. The supply gage pressure or the temperature requirement of the supply and return water to load at the interconnection point of the facility distribution system need to be incorporated to accurately model the system's thermal performance.

If the load requirements do not match the output or quality of the CHP system there may still be ways to integrate the two systems through load optimization. Facilities that require very low temperature refrigeration for cold storage, for example, can either use ammonia/water absorption or alternatively can use a LiBr absorber to cool the condenser section of a centrifugal chiller to allow it reach the lower temperatures. This way the

heat recovered from power generation can still be used without necessarily directly meeting the load quality requirements. The lower temperature condenser water produced by the absorber allows the use of a centrifugal chiller at an efficiency of 0.7 kW/ton. Without the CHP chiller, the facility would require a screw chiller using condenser water from a cooling tower which would have an efficiency of 1.5 kW/ton.

The chiller cooling tower is an integral part of the CHP system and can be used to increase system efficiency. A differentiating characteristic for CHP design versus standard HVAC design is that the CHP chiller operates at or close to full load through varying ambient conditions. HVAC design is focused on being able to meet the facility peak loads during peak ambient conditions and maximizing system efficiency through various part load conditions. For steam turbine chillers, liquid desiccants, ammonia/water absorbers and to a lesser extent, single-stage LiBr absorbers, the full load efficiency can be significantly increased at lower condenser water temperatures. This is especially valuable when the CHP system addresses both cooling and heating needs. The increase in chiller efficiency allows more of the heat recovered from the engine to be directed to offsetting heating.

When electric loads are constant but thermal loads vary widely, thermal energy storage can be used to harmonize the facility thermal load requirements with the CHP system thermal output. Where electric loads also vary significantly, electric chillers in combination with thermal energy storage may be used to level electric and thermal load profiles for high 24-hour load factor on the CHP system.

Thermal Energy Storage

In some cases the thermal load in a facility has high variations not just from peak design conditions to average ambient conditions but also from hour to hour. Figure 4-9 represents the hourly variations during a typical summer day for hot water for a large hospitality-type facility. The hot water load is highly variable through the day with the average being approximately 3 million BTU per hour (MMBH) while the minimum load is 1 MMBH and the maximum is 6 MMBH.

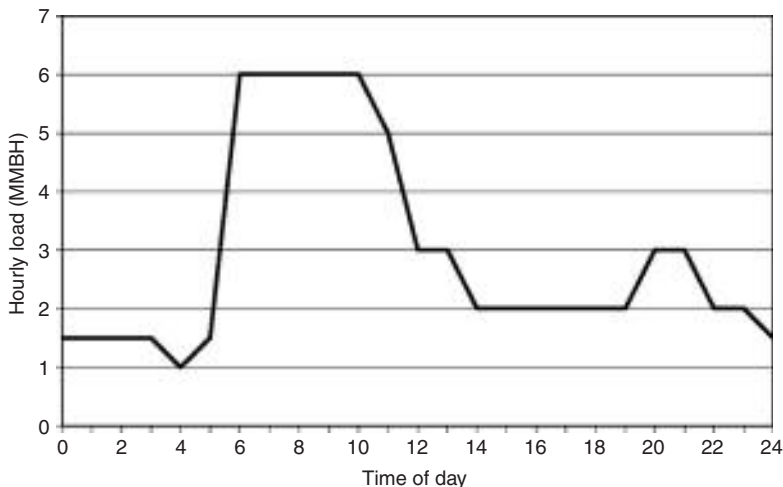


FIGURE 4-9 Daily thermal load profile for hot water in summer at a large hospitality facility. (Courtesy of Integrated CHP Systems Corporation.)

The same facility has a base electric load of close to 1 MW and a reciprocating engine CHP system with a heating T/E ratio of 4 MBH/kW would necessitate the power output be significantly reduced to meet the 1.5 MMBH 85 percent thermal base load assuming no other addressable thermal loads are available. In order to maximize the potential for the CHP system it is desirable to increase the thermal load to the 3 MMBH average but doing so would mean that the system would have many hours where the thermal energy needed to be dumped resulting in poor economic performance for much of the operating period. Thermal energy storage provides a solution that not only allows for upscaling of the CHP system to meet the electric base load but also allows for the system to meet the facility's entire hot water needs. During low thermal load hours the CHP system generates hot water in excess of the load requirements. This excess hot water can be stored and later retrieved to meet the peak loads in conjunction with the full CHP system thermal output. In this way the system can actually supply the total hot water load without the need for a supplemental boiler and so benefits from the cost offset for this boiler.

Thermal energy storage involves the transfer and retrieval of thermal energy to a storage medium. It can take many forms with the most common being water or ice as the medium contained in insulated tanks. While water and ice are common media, other media such as rock, brick, thermal oils, or chemicals can be used to also store thermal energy. Liquid desiccants provide an example of chemical storage where the desiccant can be stored in plastic tanks. Thermal storage is particularly compatible with systems that have constant energy input but varying loads as is the case with many CHP applications and as exemplified above.

For general cooling applications, ice is sometimes the storage medium of choice due to its lower space requirements versus chilled water. However, it must be remembered that many of the thermally driven technologies used in CHP applications cannot produce ice so water becomes the main choice for CHP-based cooling and heating applications. The designer of the thermal energy storage system must calculate the facility's load profile, recognize the charge and discharge characteristics of the media selected, and size the system to allow for recovery of excess output during low load periods as well as meeting the high load periods in conjunction with the CHP system output. Consideration also needs to be given to the temperature required to charge the storage medium relative to the temperature required by the distribution system as this can impact the volume of storage possible or even the type of CHP system selected.

Integration with Building Systems

Thermal design in the case of CHP systems involves one of the most important steps in the entire design process and integrates the generation process with the facility. As mentioned in the introduction to this chapter, the thermal component is key to achieving overall success and is also the most difficult component to address. When integrating a CHP system with a building or facility the thermal and electric outputs not only need to match facility needs in terms of quantity and quality, but also need to be connected to the distribution and control systems.

Integration with the building's thermal distribution system(s) requires that there be a hydronic or closed circuit heat transfer fluid loop, steam header, air duct, or other method to transfer the recoverable waste heat energy from the CHP system to the respective buildings' thermal loads. Given that most CHP systems only generate a portion of the thermal energy needs of the facility, the system needs to work in conjunction with other chillers, boilers, steam generators, etc. of different types.

Generally for hydronic loops, all the devices should be plumbed in series where possible and the CHP thermal device should be on the return side of the cooling or heating loop before it enters the non-CHP systems. This is done for two reasons, firstly and most importantly, to ensure the highest load gets applied to the CHP system. The second reason is that most of the thermally driven chilling equipment associated with CHP plants run at higher efficiencies when operated at higher evaporator temperatures. For a distribution system that supplies 42°F chilled water and receives 56°F return water, an absorber that supplies 50 percent of the load will have higher capacity and efficiency when reducing the 56°F water to 49°F than if it were to provide 42°F chilled water. In line with this concept, the flow through the CHP thermal system should be designed for the highest possible leaving water temperature for chiller applications or the lowest temperature for heating applications.

Steam generation devices will generally be interconnected to the main steam header and set at a higher pressure set point than the non-CHP boilers so that it is activated first in order to apply the maximum load to the CHP system.

When applying dehumidification or hot or chilled water or steam coils to an air handling system, the CHP-driven desiccant or coils should be placed in front of any supplementary coils such that it pretreats the air before other coils are activated.

For applications where the CHP-generated heat is applied to domestic hot water heating, it is recommended that the CHP heat exchanger be located before the fresh water is introduced to the existing or backup heating system. This provides the maximum load possible as well as the smallest heat exchanger possible. Domestic hot water heating will generally require some hot water storage and the system should also be designed to handle large flows for short periods.

As illustrated above, the CHP system can be independently controlled from temperature or pressure to ensure that it is the “first call” system. When CHP components are controlled by a comprehensive building management system, the same dispatch rules apply with the CHP system generally being first call for heating or cooling as long as the prime mover is operational.

Generally the electric power supply for the CHP-related cooling, heating, and energy distributions should be tied into the building grid rather than the generator. For many applications residual heat energy can be provided after the prime mover has shutdown and in the case of chillers, continued operation of chilled water and condenser water pumps is required to avoid damage to the equipment.

When CHP is being designed as a retrofit to existing buildings, the existing heating, cooling and power systems are left in place with the CHP system displacing output from existing systems when operational. It must be remembered that CHP systems are generally designed to offset power and fuel purchases as a way of reducing costs and emissions. They are not designed to provide continuous duty over long periods of time and are subject to shutdown for scheduled or unscheduled maintenance multiple times per year in some cases. Existing systems need to be kept on standby for duty when the CHP system is down. When CHP is designed into a new building and integrated into the thermal equipment design, some redundancy can be provided by the CHP system to help offset equipment capital costs.

In all cases CHP can best benefit an existing or new building when properly sized to meet facility loads. A properly sized CHP system provides full load power and thermal output at least 85 percent of the time on an annual basis resulting in high operational efficiency, highest possible return on investment, and ensures that the plant can operate over the intended life span of the system.

Packaged CHP Systems

Timothy C. Wagner

Thomas J. Rosfjord

Over half of the untapped 130 gigawatts (GW) of CHP potential in the United States is in commercial and institutional buildings with the vast majority of these being in sizes less than 5 megawatts (MW), as shown in Chap. 2. In this size range, custom engineering of the systems can sometimes result in unacceptable equipment and installation costs. Preengineered, packaged CHP systems have been developed to address this need.¹⁻³ These prepackaged systems provide the environmental and energy security benefits of larger CHP systems, but do so at a cost that can be competitive in many regions. This chapter describes packaged CHP systems, their benefits and shortcomings, and gives characteristic performance of commercially available packaged CHP systems.

Intrinsic Features of Packaged CHP Systems

Consumers are familiar with packaged systems. For example, every refrigerator, telephone, and automobile is a packaged system. Each is an integrated system that has been preengineered, preassembled, and prequalified to function according to customer expectations and regulatory standards. In the case of an automobile, the consumer, for example, does not buy a steering wheel, a gasoline engine, four tires, and other hardware, and then assemble them to acquire an automobile. The consumer buys an integrated system of parts recognized as an automobile and that operates safely.

Similarly, commercial and institutional clients are becoming familiar with packaged CHP systems and the values they bring. A packaged CHP system is a preengineered, preassembled, prequalified integration of a prime mover that produces electricity, a thermally activated technology (TAT) device that converts the prime mover waste heat into useful energy, and auxiliary equipment such as switchgear, controls, black-start equipment, and fuel-gas compressors. The CHP package may consist of either a single module or multiple modules, but if the latter is true, the mechanical, electrical, and communication/control interfaces between modules are precisely specified.

In contrast to a packaged CHP system, the traditional CHP system is engineered and acquired as a kit of separate parts, and then assembled to function at, and with, the

site. With advances in analysis and experience, the uncertainty of whether the assembled CHP system meets both customer expectations and regulatory requirements are reduced, but on-site engineering and fabrication are still required to ensure proper interfaces and interactions between the parts and the site. These activities may be economically acceptable for a larger CHP system, but the lower revenue of a smaller CHP system often requires minimal on-site labor to be economical. Hence, packaged systems exist for CHP systems whose electrical output power is in the order of 1 MW or less.

In the subsequent discussions, each of the primary characteristics of a packaged CHP system is described, with emphasis on how the characteristic benefits the CHP system.

Preengineered

Every CHP system is preengineered to some degree. As with every CHP system design, primary CHP system components are selected that are compatible with the utility infrastructure, provide outputs to meet customer requirements, and that satisfy safe and environmentally acceptable practices. Preengineering is particularly critical to enhance the value proposition of packaged systems through optimized design, added functionality, and minimal use of on-site labor. The preengineering benefits are

- Compatible components that are optimally integrated
- Maximum/additional functionality
- Robust system control

Preengineering ensures that the prime mover and TAT device are optimally matched to achieve the highest level of fuel utilization, defined as the quotient of useful electrical and thermal output energy to fuel input energy (see Chap. 17). The TAT device capacity must be consistent with the quantity and quality of waste heat available. Additionally, proper matching ensures that the properties of the waste heat leaving the prime mover can be efficiently used as input to the TAT device. For example, if the TAT device imposes excessive pressure loss at the waste heat flow rate, then the prime mover will experience excessive backpressure and its output may be unacceptably degraded. Or, if the waste heat temperature exceeds a TAT device allowable limit, a wasteful heat loss could be required to reduce temperature. In either case, the system output and fuel utilization are reduced. Preengineering can avoid these issues through the proper selection of components, including the selection of multiple or multimode TAT devices. For example, a heat exchanger to heat air or water may alleviate the above excessive inlet temperature issue while producing another useful energy stream.

Preengineering can add functionality to the CHP system. For example, the selected TAT device might be capable of providing alternative thermal energy streams such as heating or air-conditioning, thereby expanding the utility of the CHP system. The system can also be designed to have dual mode capability. In this case, the CHP system can operate either parallel to the utility electrical grid ("grid connected") or independent of the grid ("grid independent" or "island-mode"). Preengineering ensures the existence of the proper technology to meet required start-up or transition timing. The CHP system can be preengineered to operate on multiple fuels if the appropriate pumping, valves (including fluid compatible internal materials), metering, and emission control devices are properly integrated. As described below, added functionality can provide a distinguishing performance benefit for a packaged CHP system.

A critical aspect of preengineering is establishing the control system to help ensure that the system operates predictably, reliably, and safely. The control system ensures that the prime mover and TAT device operate as a system, recognizing that demands on one unit affect the other unit, but the two devices likely have significantly different response times. The consequences of a failure by one device, or the utility infrastructure, may require protective steps by the other device, and neither unit is ever permitted to operate outside its safe design space. These capabilities must be achieved for all steady-state and transient conditions, including the transitions associated with dual mode or multiple fuel capabilities.

Preamsembled

The packaged CHP system is preassembled into a single module, or a few number of modules, prior to shipping to a host site. In general, any module is designed to require minimal on-site labor by including all components or auxiliary equipment, enclosures, and precisely defined mechanical, electrical, and communication/control interfaces both between individual modules and between the modules and the site. This includes providing a support structure that efficiently integrates with building structures, clear points for safe hoisting, and clear and separated fuel and electrical connectors. The size and weight of each module must conform to shipping standards, and consider constraints to on-site options to locate it (e.g., standard elevator access and standard doorway opening).

An important consideration of the module design is to ensure that component and equipment layout does not compromise system performance. Inlet airflow, waste heat gas, and exhaust flow paths cannot be long or tortuous. Proper thermal insulation must be used to minimize energy loss, and isolation/ventilation used to avoid excessive heating of components with maximum temperature limits or significant thermal degradation (e.g., valves and electronics).

The module design should allow for efficient manufacturing and maintenance. Component and equipment layout must consider fuel, electrical, and communication requirements and the standardized methods (e.g., conduit layout, pipe size, and assembly) to provide these services; codes can dictate acceptable options. The layout should allow for an orderly assembly process (i.e., a component assembly can be completed without interference from another device), including allowing intermediate quality checks. Simultaneously, the component and equipment layout must provide maintenance accessibility, allowing the use of larger equipment (e.g., a fork lift) if required. Routine maintenance items should be particularly accessible. Part of the maintenance consideration is specifying a durable enclosure to provide environmental protection from rain, snow, wind, dirt, etc. The enclosure must include sealed access openings, ventilation, and all code-required exterior safety markings such as for hot surfaces and electrical voltage, for example.

A preassembled module of a packaged CHP system should be carefully inspected to ensure that it conforms to the assembly process guidelines prior to shipment. This includes ensuring that proper techniques were used (e.g., welded versus screwed pipe assembly, electrical and communication wiring separation, secure component mounting) and proper enclosure labels are visible (e.g., fuel, electrical voltage, and hot surfaces). Performance testing prior to shipment should be part of its prequalification.

Prequalified

A packaged CHP system that is rigorously preengineered and preassembled should operate as expected when shipped to a customer site. Prior to sale a prototype system should be fully validated and module designs must address all key issues. Therefore, rigorous field testing of packaged CHP systems must be undertaken to ensure that all of the features and capacities listed in catalogues are demonstrated prior to sales release. Only in this manner will the packaged CHP system value proposition be enhanced. Specialized test facilities that provide electrical and thermal load banks are used to validate a prototype packaged CHP system for

1. Steady-state performance guarantees both at a rating condition such as ISO⁴ or ARI⁵ standards and for variations in the ambient temperature and pressure.
2. Environmental outputs, both regulated exhaust emissions and noise, at these conditions.
3. Transient response to component or utility failures, and changes of the site electrical or thermal demands.
4. Dual-mode transition and start-up.
5. Multifuel transition and the system transient response for each fuel, if applicable.
6. Robust control system that guarantees predictable, reliable, and safe operation for all the above issues and interfaces with the site to ensure that all foreseeable load demands are met.

To ensure that each assembled packaged system performs as the prototype, a series of qualification tests may also be performed including verifying the design point electrical output, thermal output, and CHP system efficiency. Since the concentration of undesirable exhaust emissions are usually regulated, they should also be measured for compliance with local environmental codes prior to shipment. All of these tests must also verify the functionality of the system controls and data communication.

Benefits and Shortcomings of Packaged CHP Systems

A packaged CHP system containing the above intrinsic features has many values beyond those sometimes afforded by a traditional custom engineered CHP system. In particular, the packaged system can have

- Enhanced performance
- Lower adverse environmental impact
- Higher reliability
- Better economic value

Each of these benefits is expanded upon in subsequent paragraphs. The packaged CHP system does present certain shortcomings, however. Because the packaged system outputs are optimized, they are well defined and rather inflexible. That is, the packaged CHP system provides great value for a limited range of combined electrical and thermal output energy, but it is likely incapable or inefficient to operate at greatly different

outputs. This inflexibility means that in order to use packaged systems, a family of packaged systems must be available to meet the energy demand for a wide range of applications. Further, the preengineered/preassembled features result in a well-defined layout that may not have the flexibility to be installed at every site. Modularity mitigates this restriction but does not eliminate it. Hence, the desirable features of a packaged CHP system may yield degrees of output or layout inflexibility that could be best addressed by similar offerings in a family of packaged CHP systems.

Enhanced Performance

The packaged CHP system is preengineered to maximize both the output energies of the prime mover and TAT device, and the CHP (or fuel utilization) efficiency to produce them. These features are accomplished through the proper matching of the major CHP components and their operating characteristics and requirements. Parasitic losses are minimized. Therefore, a packaged CHP system can achieve, at least, a slightly higher performance than a similar system that is custom engineered for the site. However, the primary performance benefit of a packaged CHP system comes from its expanded functionality.

Any CHP system will achieve a high level of performance if it is base loaded to match the energy demands of a facility and, therefore, operates continuously. Such a situation may be encountered with small- and moderate-sized industrial customers who employ a process with a continuous thermal energy demand such as for hot water. This situation may also be encountered for commercial customers located in climates where the building requires either continuous space heating or continuous space cooling.

There are, however, many CHP opportunities for customers, particularly commercial, governmental, and institutional customers, when the thermal energy demand is not continuous throughout the year. Under such circumstances, the ability of the CHP system to deliver alternative thermal energy outputs (e.g., hot water for space heating, domestic hot water, and chilled water) becomes critical to realizing the significant CHP performance advantage over the traditional utility methods delivering comparable energy streams.

The ability of a CHP system to deliver alternative energy outputs can be a complex challenge. It requires: (1) engineering efforts to select and match components, and to develop the control strategies to ensure that the system operates reliably and safely; (2) system design and assembly efforts to ensure that component placement does not compromise performance such as may be encountered with longer duct runs or thermal effects; and (3) system validation/qualification efforts to ensure that the system achieves its promised performance. These three characteristics must match those of a properly designed packaged CHP system. Hence, the expanded functionality of a well-planned packaged CHP system can provide a more cost-effective pathway to achieve high performance for customers with noncontinuous energy demands. In some circumstances, properly engineered packaged CHP systems are the most cost-effective means available to achieve acceptable performance for customer needs.

Note that “enhanced performance” is also one of several benefits of selecting a packaged CHP system. There are instances when the lower installation cost of a packaged CHP system—without expanded functionality—justifies its selection as the preferred approach to meet noncontinuous energy demands.

The following analysis results illustrate the performance benefits of expanded functionality packaged CHP systems. Consider three packaged CHP systems:

- System 1 can deliver electrical and hot water energies
- System 2 can deliver electrical and chilling (i. e., air-conditioning) energies
- System 3 can deliver electrical, and either hot water or chilling energies

Specific characteristics of the three systems at design point operating conditions are contained in Table 5-1. The electrical efficiency η_e is representative of a microturbine prime mover. The heating output H was calculated based on converting 75 percent of the prime mover exhaust heat to usable hot water after 5 percent parasitic losses. The chilling output C was calculated based on capturing 50 percent of the exhaust heat after 5 percent parasitic losses, and converting the captured energy into chilling with a double-effect absorption chiller with $COP = 1.3$. The CHP efficiencies η_{CHP} of Systems 1 and 2 were based on this rating condition; the CHP efficiency of System 3 depends on how it is operated—that is, hours of heating and hours of chilling. For analysis purposes, the capacities of these systems were specified to be arbitrarily small; performance parameters (e.g., η_e) are assumed achievable such as have been demonstrated in larger systems.

The performance of these three CHP systems should be compared to delivering the same energy by more traditional methods. For the traditional methods, the utility grid was assigned an efficiency: $\eta_{grid} = 35$ percent (LHV), the traditional boiler assigned an efficiency: $\eta_{boiler} = 88$ percent (LHV), and the chilling was assumed to be produced by an electric-grid chiller with coefficient of performance: $COP_c = 3.5$.

First, consider the performance of Systems 1 and 2 if operated continuously. Figure 5-1 compares the efficiency of each system to the traditional means to deliver the same energy. As expected the CHP systems achieve significantly higher efficiency and consequently, a fuel savings of 30 percent and 17 percent for the $E + H$ and $E + C$ systems, respectively, would be realized versus a more traditional system. The reason for the lower fuel savings with the $E + C$ system is because of the very effective traditional electrical chiller with $COP_c = 3.5$. Nevertheless, any CHP system that operates continuously performs well and significantly reduces overall fuel consumption.

System: Outputs			1: E + H	2: E + C	3: E + H + C
Electrical power	P_e	kW	30	30	30
Heating	H	Btu/h	170K	0	170K
		kW	50	0	50
Chilling	C	RT	0	12.3	12.3
		kW	0	43	43
Electrical efficiency	η_e	% (LHV)	30	30	30
CHP efficiency	η_{CHP}	% (LHV)	80	73	77*

*Assuming 60 percent heating and 40 percent cooling.

TABLE 5-1 Design Point Operating Characteristics of Alternative Packaged CHP Systems

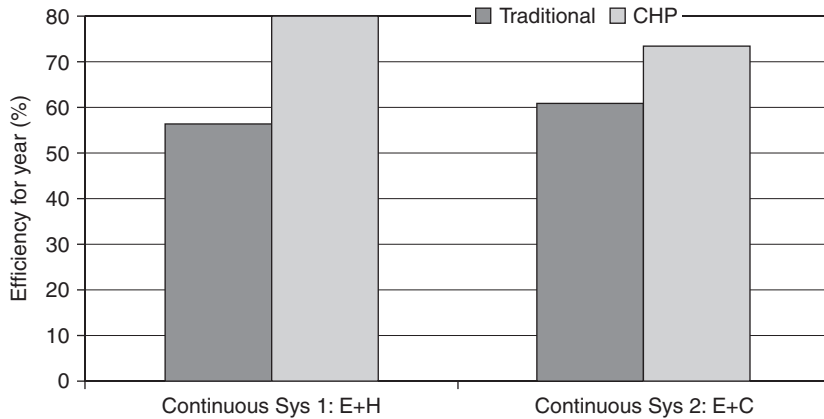


FIGURE 5-1 Continuously operated CHP systems outperform traditional energy systems.

Second, consider the three packaged CHP systems when operated at customers with seasonal thermal energy demands. These demands were assigned as indicted in Table 5-2. Five-month seasonal periods were assigned to either heating or cooling, with continuous demand for electricity. The table also indicates the periods of energy delivery from the power grid, boiler, and electric chiller so that the total energy delivered by the CHP and traditional approaches were equal. It was recognized that if an electric power-only period was eliminated for a CHP system, the energy delivery efficiency would improve. However, the corresponding utilization of the system (i.e., hours per year) would reduce, adversely affecting the economic metric of number of “years for pay-back.” This effect would be great for Systems 1 and 2 but less significant for System 3.

Figure 5-2 compares the yearly efficiency of delivering the electrical and thermal energies for the three packaged CHP systems with traditional methods for the above assumed use profiles. These results indicate that CHP systems with a single thermal output may have only a slight performance advantage over traditional methods if not all of the thermal output can be beneficially used by the facility; System 2: $E + C$ appears to have no advantage. Again, note that other factors such as “economic benefits” may justify the selection of a single thermal output CHP system for a seasonal demand. However, only System 3 distinguished itself as significantly outperforming traditional

CHP Packaged System		1: $E + H$	2: $E + C$	3: $E + H + C$
CHP operation	Months with $E + H$	5	0	5
	Months with $E + C$	0	5	5
	Months with E only	7	7	2
Traditional operation	Months of grid	12	12	12
	Months of boiler	5	0	5
	Months of chiller	0	5	5

TABLE 5-2 Operating Periods for Seasonal Demand

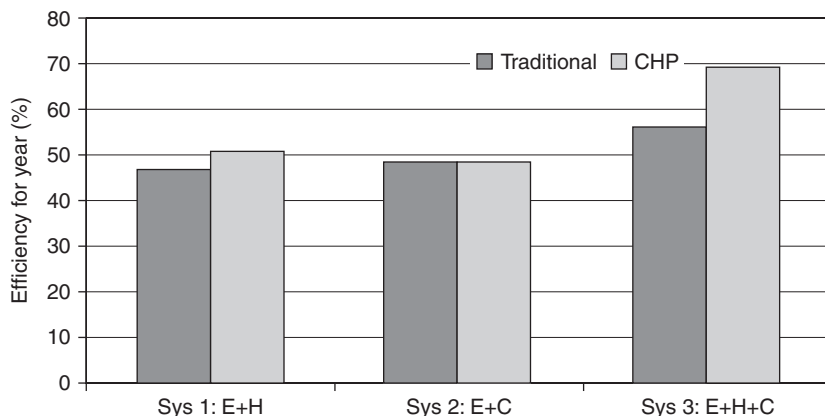


FIGURE 5-2 Packaged CHP system with added functionality outperforms traditional energy system for seasonal demands.

methods for the year, because all of the available thermal output from the recovered waste heat is fully utilized. The corresponding yearly fuel savings is 19 percent.

Hence, while any continuously operated CHP system outperforms traditional methods to deliver the same energy, the added functionality available from a packaged CHP system outperforms traditional methods for the numerous customers with seasonal thermal energy demands.

Lower Adverse Environmental Impact

As discussed in Chaps. 1 and 7, a CHP system impacts the environment by emitting a quantity of undesirable emissions—including carbon dioxide (CO_2), carbon monoxide (CO), unburned hydrocarbons (HC), and nitric oxides (NO_x)—that it exhausts. CO_2 is a greenhouse gas that relates directly to the quantity and composition of the fuel consumed. Fuel savings and/or the use of lower carbon content fuel will reduce CO_2 emissions. Other emissions may result depending upon the efficiency of combustion features used in the prime mover, with CO and HC representing incomplete combustion and high levels of NO_x being formed in regions of excessive temperature.

Any CHP system that operates continuously achieves high system efficiency with a corresponding decrease in fuel consumption when compared to traditional methods to deliver the same energy. However, a CHP system that operates with seasonal thermal energy demand constraints may not be able to reduce fuel consumption or CO_2 . Figure 5-3 depicts the predicted yearly CO_2 reduction for the three CHP systems analyzed above. Since only System 3 achieved a distinct energy performance enhancement over traditional energy delivery methods based on full utilization of the available thermal output, only a functional compatible packaged CHP system achieves significant yearly CO_2 reduction with seasonal thermal demands. Better results are generally achieved when energy is produced from natural gas, the fuel of choice for many CHP systems. In reality, the CO_2 reduction with CHP is even greater because 50 percent of traditional U.S. electrical power plants burn coal and thereby produce greater CO_2 per kilowatt than for natural gas.

A CHP system also produces low quantities of undesirable exhaust emissions of CO, HC, and NO_x because the prime mover usually employs the latest combustion

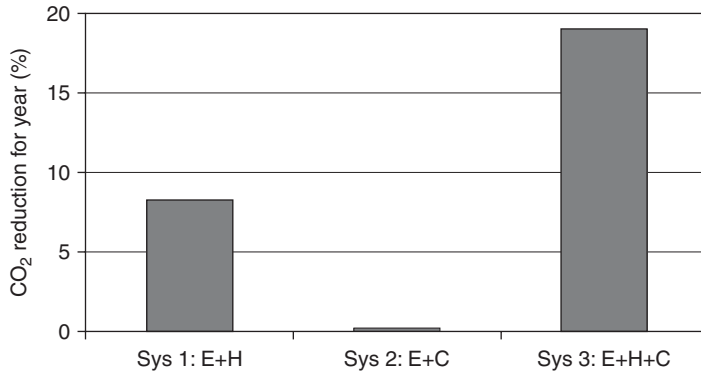


FIGURE 5-3 Packaged CHP system with added functionality reduces greenhouse gas emissions for seasonal thermal demands.

control technology. This results in the lowest pollutant per unit of input fuel. The limiting case is a fuel cell prime mover which does not use a combustion process and produces practically zero concentrations of these emissions.

Further, regulators recognize that the effective metric is pollutant per unit of output energy which can be represented as

$$\begin{aligned} \text{Pollutant/output energy} &= (\text{pollutant/input fuel} \times \text{input fuel}) / \text{output energy} \\ &\cong \text{combustion control technology} / \text{fuel utilization} \end{aligned}$$

Hence, the CHP system minimizes this pollution metric by both employing the best pollution control technology (i.e., lower pollutant per unit input fuel) and achieving the highest fuel utilization (i.e., using the lowest amount of fuel per unit output).

While greenhouse gas (GHG) and regulated pollutant benefits are realized by all CHP systems, they can be maximized with a packaged CHP system because of the performance and fuel utilization benefits described above. A packaged CHP system can also be designed to yield lower waste material at an installation site because of its precisely defined mechanical, electrical, and communication/control interfaces.

Higher Reliability

The higher reliability of a packaged CHP system derives primarily from the extensive prototype validation testing and the assembled system qualification testing described previously. The control system is validated both to achieve desired outputs and to limit operation outside of safe component capabilities. Scheduled maintenance is often better defined. The entire package assembly can be inspected to ensure mechanical and electrical quality. In this manner, the packaged CHP system can be relied upon to deliver predictable performance capability and a low probability of premature equipment failure.

Better Economic Value

Economic value becomes a critical feature to be considered during the preengineering, preassembly, and prequalification steps of a packaged CHP system development. In addition to maximizing useful outputs, steps can be undertaken to help ensure duplication

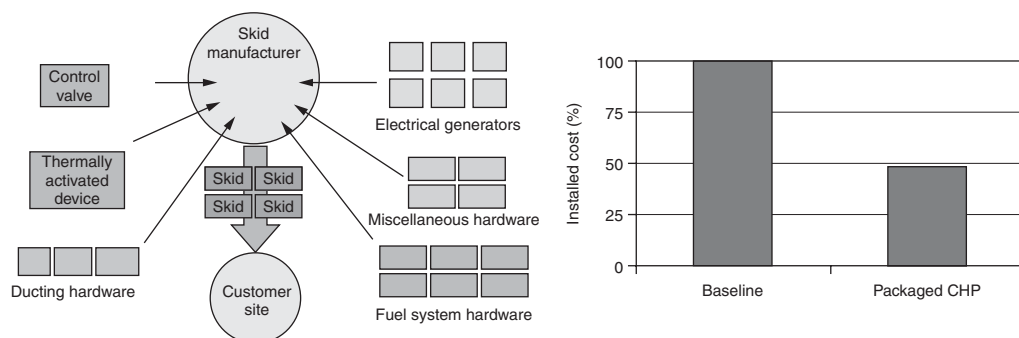


FIGURE 5-4 Cost-benefit of packaged CHP systems.

of minimal levels of fuel consumption, on-site installation time and labor, and maintenance time and labor. Maximum output and minimal installation features help reduce the first cost of the system by right sizing the components and equipment, while the fuel and maintenance features can minimize operating cost. The importance of minimizing on-site installation time cannot be overemphasized (Fig. 5-4). These costs can represent a significant portion of a package CHP system overall cost because industry recognized package CHP installation protocols are not yet fully standardized and local labor rates can be high. Packaged system utilization can be extended through the proper selection of the TAT device such as the use of an absorption chiller to permit seasonal cooling or heating. Also capabilities such as dual mode operation to ensure power delivery to critical devices or processes in the event of utility interruption can be included to enhance the value of the packaged CHP system. In this case, the added value is the avoided cost of lost revenue or work in process.

Together, all these features contribute to shorten the system payback, the time period required for operational savings to offset initial costs (see Chap. 9). So whether the customer is motivated by first cost or payback, the intrinsic features of a packaged CHP system offers economic advantages over the traditional system.

Examples of Commercially Available Packaged CHP Systems

While custom engineered CHP systems have been common for many years, fully packaged CHP systems—catalog systems that are preengineered, preassembled, and prequalified prior to shipping to a customer site—are only presently available from a limited number of manufacturers. The most common packaged CHP systems are $E + H$ systems that provide electricity and hot water. Packaged $E + H + C$ systems that deliver electricity, cooling (chilled water), and heating are much less common. The purpose of this section is to provide characteristic performance of packaged CHP systems that cover a range of sizes and prime mover technologies.

Power/Hot Water Systems

Most packaged CHP systems couple a prime mover and its companion generator with a heat recovery unit to recover energy in the form of hot water ($E + H$). In some cases, the heat recovery unit is an integral part of the prime mover design. For example, this

Prime Mover	Power Rating (kW)	Electrical Efficiency (%)	Thermal Output (MMBtu/h)	CHP Efficiency (%)
Fuel cell	300	47*	0.48 [†]	69
	400	42*	1.60 [‡]	91
Microturbine	65	29	0.41 [‡]	83
	200	31	0.84 [‡]	69
	250	30	1.00 [‡]	65
Reciprocating engine	153	32.3	0.95 [§]	91
	250	30.6	1.57 [§]	87
	385	32.3	2.13 [§]	85

*Beginning of life (BOL).

[†]At 250°F.

[‡]At 140°F.

[§]At 160°F.

TABLE 5-3 Packaged $E + H$ CHP Design Point System Performance

approach is used for fuel cell prime movers where cell stack heat is removed and then made available as hot water. The $E + H$ CHP systems are also available with combustion turbine prime movers. In this case, the energy in the exhaust flow is recovered in an exhaust-to-water heat exchanger. A third family of $E + H$ CHP systems utilizes reciprocating engine prime movers. In these systems, energy is recovered from both the jacket water and from the exhaust. Typical electrical performance and thermal output for fuel cell, microturbine, and reciprocating engine $E + H$ CHP systems is presented in Table 5-3. Note that the performance presented is for continuous operation at the design point. Annual performance in a given application is dependent on utilization of the electrical and thermal outputs.

Power/Cooling/Heating Systems

Power/cooling/heating systems use the exhaust energy to provide chilled and hot water. While these systems have a higher first cost than $E + H$ systems, they can provide a better value proposition for applications requiring both heating and cooling. The $E + H + C$ systems are also called combined cooling, heating, and power (CCHP) or tri-generation systems. In such systems, chilling is typically accomplished by using the exhaust energy to drive a lithium bromide/water absorption chiller as discussed in Chap. 4. While many companies will design and fabricate such systems, commercially available packaged $E + H + C$ systems are not yet widely available in the marketplace. One commercially available system features the integration of microturbines and a double effect absorption chiller. The performance features of the latter system are presented in Table 5-4. As was the case for the $E + H$ systems, it should be noted that the performance presented is for continuous operation at the design point. Annual performance in a given application is dependent on utilization of the electrical and thermal outputs. The multiple outputs provided by $E + H + C$ systems often enable them to achieve higher annualize performance than $E + H$ systems.

Prime Mover	Power Rating (kW)	Electrical Efficiency (%)	Thermal Output (Heating) (MMBtu/h)	Thermal Output (Chilling) (RT)	CHP Efficiency (%)
Microturbine	400	31	1.45*	181 [†]	0.70

* At 175°F.
† At 54°F inlet/ 44°F outlet/ 64°F cooling water inlet.

TABLE 5-4 Packaged E + H + C CHP System Design Point Performance

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Regulatory Issues

Gearoid Foley

CHP systems are covered by various federal, state, and local regulations, which must be thoroughly understood by anyone either considering installing a CHP system or by anyone operating a CHP system. Regulations can influence the sizing, selection, and cost of the CHP system, define minimum efficiencies, and can provide financial support. Other key regulations control allowable emissions and interconnection methods which in turn affect CHP system configuration as well as accessory equipment requirements. This chapter discusses the development of CHP related regulations from a U.S. federal and state perspective as well as briefly look at some of the international regulations.

It has been said that most of the benefits derived from CHP are in fact societal rather than accruing to the owner such that it is in the best interest of the public to support CHP wherever it can. As recognition of CHP's sustainable role in meeting greenhouse gas (GHG) emission reduction targets gains traction, many state authorities have proposed new regulations that will help encourage the industry including, in some cases, consideration of CHP as a "renewable" energy resource. In addition, the role of CHP as a tool to bolster grid reliability has long been understood and is starting to be adopted at a state and even at an electric utility level as a way to avoid expensive infrastructure upgrades to the electric distribution system. As a secondary benefit to relieving power grid congestion, implementing CHP can also help reduce the local demand for electric power transmitted from outside the local region and therefore influence the electric price downward. From a security and environmental point of view, the high fuel efficiency of CHP versus central power generation and separate heat generation, means less fuel required from outside sources as well as less emissions. As all these benefits offered by CHP are becoming recognized as societal benefits, we see public policy changing to encourage and assist CHP installations. From federal to state to even utility and local authority level, changes are taking place to reduce barriers to CHP implementation as well as financially support CHP.

U.S. Federal CHP Policy

The role of the federal government in regulating CHP is somewhat limited based on the conflict between individual state jurisdiction versus federal jurisdiction over power generation, transmission, distribution, and environmental issues. The federal government's

role has increased somewhat over the past decades as energy policy has increasingly been viewed as a national issue from an economic, security, and environmental perspective.

As noted in Chap. 1, in the United States, after the energy crisis of the 1970s, federal regulations became a significant influence on large-scale CHP plant development due to enactment of the Public Utility Regulatory Policies Act (PURPA) of 1978. This legislation created a nonutility power market by forcing utilities to purchase power generated by PURPA *qualified facilities* while exempting these facilities from the need to actually be a utility. It allowed the CHP plant access to the wholesale power market and also required the utility to provide backup power service at a reasonable cost. To become a qualified facility, the CHP plant needed to generate both electric power and at least 15 percent useful thermal energy from a single fuel source and the total power output plus one-half of the thermal output had to be no less than 42.5 percent of the total fuel input on an annual basis when using oil or natural gas. This in essence allowed large thermal energy users to build CHP plants to meet thermal needs and sell the excess power generated in the process to the utilities at a rate that made these plants economically viable. Recognizing that electric power market deregulation in effect opened the market to all power suppliers including nonutility facilities, the Energy Policy Act of 2005 (EPACT 05) removed the requirement for utilities to purchase power from PURPA qualified facilities in regions where the electric power market had been deregulated. The removal of this requirement has resulted in the many of the CHP plants that operated as PURPA qualified facilities to now become economically nonviable through most of the year based on the wholesale price of electric power and the cost of transporting the power from the CHP plant to the wholesale market. As pre-EPACT 05 contracts expire many of these CHP plants have been forced to either shutdown completely or operate as peaking plants that supply power to the grid only in times of high demand when power prices on the wholesale market can justify operating expenses. These plants can therefore no longer meet the thermal needs of their former clients and no longer function as CHP plants.

While the change in policy toward PURPA qualified facilities has reduced the viability of CHP plants designed to export power, the general trend in federal legislation has been to open the market for CHP, recognizing its beneficial impact on fossil fuel use and reduced greenhouse gas emissions. Further, sustainable on-site CHP that meets the base load or a portion of the facility's load is often economically viable. The Energy Policy Act of 2005 did add some momentum to the growth of CHP by providing a 30 percent tax credit for fuel cells and a 10 percent tax credit for microturbine-based power generation systems and extending federal energy procurement contract authorization to 10 years. It provided funds for further study on energy efficiency benefits, technology, and integration of power generation with the grid. It also provided for improvement of natural gas supply (the most common CHP fuel) through clarification of federal authority on liquefied natural gas facilities as well as transmission lines and amended some tax laws to help incentives distribution system construction.

Late in 2008, the passage of the Energy Improvement and Extension Act of 2008 contained some additional incentives for CHP including a 10 percent investment tax credit for CHP through 2016 as well as allowing a 5-year accelerated depreciation schedule for CHP systems. The act also extended the EPACT 05 tax credits for fuel cells and microturbines through 2016.

The federal government also has significant impact on the development of CHP through its environmental policies and in particular through its air emissions regulations.

The federal Clean Air Act of 1970 and its amendments that regulate air emissions from stationary engines such as those used to power CHP systems is the most significant emissions related legislation. The Clean Air Act required the U.S. Environmental Protection Agency (EPA) to establish ambient air quality standards to protect public health and the environment. These National Ambient Air Quality Standards (NAAQS) are the metric for the emissions compliance for CHP applications and have limits for six criteria pollutants of which NO_x , CO, SO_2 , and particulate matter (PM) are of the greatest relevance to CHP systems (see Chap. 7). Most CHP systems employed today operate with natural gas as the main fuel source so the criteria pollutant of most concern for CHP systems is NO_x . Ambient air is classified by region as either “in attainment” or “nonattainment” for a given pollutant. Areas that are in nonattainment for NO_x will be required to meet lower emission levels than those areas that are in attainment and will most likely require the addition of post-combustion treatment of exhaust to meet the emissions requirements.

While the NAAQS are standards for ambient air quality, there are also equipment-based performance standards and *new source review* requirements established by the federal government but which are implemented by state authorities. CHP plant developers are required to apply for preconstruction environmental permits (see Chap. 12) that will generally be categorized according to the annual volume of specific pollutants that the proposed CHP plant has the potential to emit. The potential to emit is calculated on the total emissions from the plant running at full output for all operating hours. Large plants that exceed certain total annual emissions thresholds are considered a major source. As such they are subject to regulation according to federal standards as implemented by the state. Plants that emit less than these major sources are subject to state regulated “minor source review” and small plants that are under state specified thresholds may be exempt from permit requirements. Small plants and minor source plants are generally subject to state regulations which are designed to meet federal standards at a minimum but which may also be considerably more restrictive than federal standards. The air permitting process is generally used to define the type of pollution control device to be used in order that the CHP plant may obtain a permit to construct and a permit to operate. In all cases the air permit requirements for CHP plants needs to meet federal standards as well as be in compliance with local regulations.

U.S. State CHP Policy

As indicated above, the influence of the federal government on the development of CHP in the United States is somewhat limited due to jurisdictional issues. The PURPA regulations introduced in the late 1970s gave a strong boost to large-scale CHP for three decades but the economic benefits provided by this federal legislation are no longer available in most regions. Until the 10 percent investment tax credit recently enacted, there has been little material support for CHP over the past three decades from the federal government. The U.S Department of Energy has generally been sympathetic to CHP and has implemented various CHP-related research and demonstration programs, but has been prevented from providing significant material support due to budget appropriations for CHP being relatively small.

In trying to overcome the many roadblocks that prevent wide implementation of CHP it has become apparent that the individual states play a much more significant role

than the federal government. While federal incentives such as tax credits can have a considerable impact on economic barriers, there are many other barriers that have traditionally stood in the way of CHP implementation. These barriers are varied but do include such issues as interconnection with the local power grid, local emissions regulations, permit approval time, citing restrictions, etc. as well as capital cost. Many of these issues including to some extent cost, are actually controlled at a local, utility or state level. Also in most cases the local and utility influenced issues are actually overseen or regulated by the state.

Interconnection with the electric grid is a good example of the development of state influence over CHP development. Originally interconnection with the utility power distribution grid was regulated directly by the local utility. In the post-PURPA era a natural gas-fired CHP plant generally will not export electricity to the wholesale market as it is not economically feasible to do so nor will it be sized to meet the peak power needs of the host facility for the same reason. It must, therefore, work in conjunction with and be interconnected to the local power grid to be economically feasible. Obtaining an interconnection agreement with the local utility became a significant barrier to the implementation of CHP until some states took control of the situation and developed a statewide standard interconnection specification, which they were able to force the utilities to accept including defining maximum response times on applications by the utility. This type of action has served to significantly reduce this barrier for many projects within states that have standard interconnect agreements such as California and New York. In all cases, the *interconnection agreement* must still be accepted by the local utility but standards imposed by the state provide some formality and recourse to the applicant.

Emission requirements can also be a significant barrier that is generally controlled at the state level. While the federal EPA has the authority to designate areas of attainment or nonattainment for various criteria pollutants, the state air quality management agencies administer the programs relating to air quality. For all but the largest CHP plants the state agency responsible for air quality sets the emissions standards so that they can meet federal air quality standards at a minimum. Emissions standards for CHP do vary considerably from state to state as well as within each state depending on its federal air quality standard attainment status. In general for natural gas-fired CHP plants, which (as shown in Chap. 2) represent the majority of plants, the main criteria pollutant of concern is nitrous oxides (NO_x) which is a precursor to ground level ozone and so ozone level attainment status is a significant indication of how tough emission requirements will be. Areas that are in noncompliance with federal EPA standards for ozone will require that CHP plants emit less NO_x than plants that are located in attainment areas.

A significant policy change that supports deployment of CHP in many states has been the recognition of the effect of the increased CHP fuel efficiency versus central power generation on emissions. Using less fuel by offsetting boiler operation with waste heat from a CHP plant directly reduces the emissions that would have resulted from the operation of the boiler. Some states, such as California, give an emissions credit for the energy recovered from power generation for useful purposes that can be added to the power output of the system when calculating emissions rates per unit of output. In this scenario the total system emissions are calculated by adding the useful thermal output to the power output, the total of which is then divided by the emissions to calculate the pounds per unit output (typically kW or MW) of a particular pollutant. This

method lowers the emissions rate for a given system and makes it easier to comply with local air quality standards.

Issues such as energy costs, electric power grid reliability, and air quality are of significant concern to individual state governments and impact in-state industrial competitiveness, job growth, as well as health costs. The benefits offered by CHP in all of these areas are recognized by many state governments and have led to the creation of incentive programs by some states to try to encourage wider implementation of CHP. These programs vary in nature but are typically based on providing capital grants, tax credits, or production payments over a specified period. The major requirements for obtaining such incentives are that the CHP plant meets local air quality standards and that the plant also meets a predetermined efficiency rate typically calculated on an annual basis (e.g., 60 percent efficiency based on the sum of electric plus useful thermal output divided by fuel input). Such investments by the state are typically paid for using levies on electric power rates which are reinvested in CHP systems in an effort to offset power grid infrastructure improvement costs as well as reduce power costs which are often related to regional power transportation congestion. Having CHP plants built in congested areas reduces the demand to bring power to the area resulting in lower power costs in that particular area.

Another area of change from a state policy perspective is the growth in requirements by in-state utilities to provide a portion of their power from renewable or clean sources which in some cases include CHP. North Carolina allows up to 40 percent of the renewable energy portfolio to be met with energy efficiency including CHP. In other cases there is a portion of the renewable or clean energy portfolio set aside for CHP. Growth in the desire of states to impose requirements for clean energy supply combined with the recognition that CHP offers a very cost-effective way to provide clean power have led to more emphasis being placed on CHP as a way to meet emissions reduction goals at a reasonable cost.

Non-U.S. Policy

Many countries have long embraced CHP for district heating and cooling applications. While the United States leads the world in terms of total CHP power output, many countries in Western Europe have a significantly higher portion of their electricity produced from CHP. Denmark leads the world in CHP penetration with over 50 percent of its power produced from CHP according to the International Energy Agency (IEA). This high penetration is facilitated by a high urban population and the related presence of district heating and cooling systems many of which are publicly funded and owned. Germany is similar to the United States in having most of its CHP installation base in the industrial sector. Eastern Europe also has a relatively high portion of its power production coming from publicly owned CHP systems tied into thermal distribution systems. In China a significant portion of district heating systems are supplied by CHP resulting in approximately 13 percent of power production coming from CHP according to the IEA. Figure 6-1 shows the percentage of power provided by CHP for the G8+5 countries as reported by the IEA.

European CHP-related policy varies by country and include subsidy payments for CHP plants that feed into the utility grid, preferential priority in order of dispatch, mandatory use of CHP for generating power to exemption for a building from the requirement to purchase renewable power if a CHP system is installed.

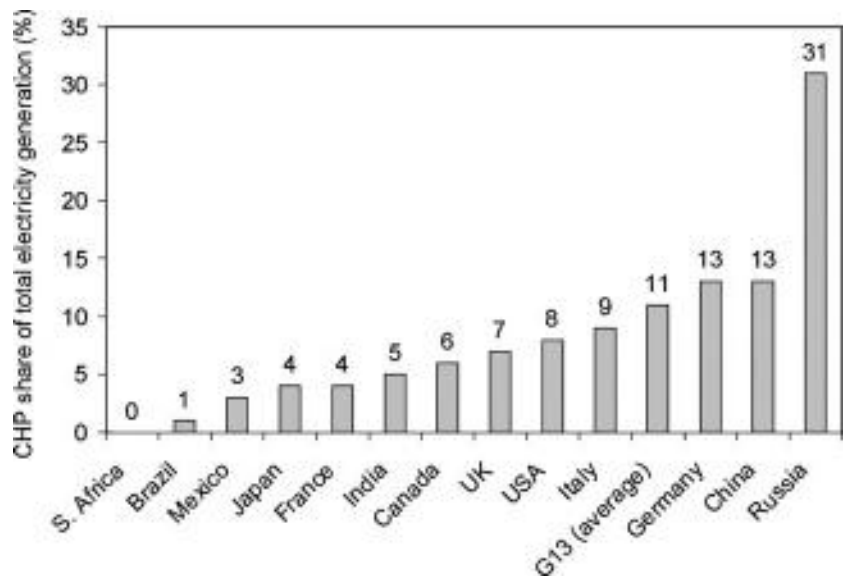


FIGURE 6-1 CHP generation as a share of total electricity for the G8+5 countries. (Source: International Energy Agency report on CHP dated March 2008.)

CHP Programs

The individual states can also offer other forms of support for CHP such as streamlined air permitting procedures and exemptions from sales tax for CHP fuel. The following examples look at some of the state-specific programs designed to assist the implementation of CHP.

NYSERDA DG-CHP Demonstration Program

New York through the New York State Energy Research & Development Agency (NYSERDA) offers significant capital cost grant support for implementation of CHP. These programs are offered through a competitive bid process and are generally renewed when the appropriated funding for a particular program has been drawn down. The current program for demonstration of distributed generation as combined heat and power has funding of \$25 million and offers 30 to 50 percent cost share from the state up to a maximum of \$2 million for any one project. The program also includes the same level of cost share with a maximum of \$4 million for fleet demonstration projects where by up to four CHP plants can obtain funding of \$1 million each for a client who has multiple sites. In addition, the program covers support for recommissioning studies for existing NYSERDA-funded projects as well as support for technology transfer studies to broaden CHP market penetration.

For CHP demonstration projects the program is targeted at supporting installations that provide superior environmental performance, improve grid reliability and energy efficiency, increase utilization of renewable fuels, and reduce energy costs in order to foster economic expansion. These goals embody the typical focus for most of these

state-sponsored CHP assistance programs. The base program funding level is 30 percent with an additional 10 percent being given if the project meets certain additional criteria including being located in Consolidated Edison territory (i.e., located in New York City), being connected to a spot network as opposed to a radial grid, being designed to provide “flicker free” transition between normal and backup power modes or if the project utilizes preengineered prefabricated, factory-tested modules that integrate electric generation with thermal systems. Each criteria met will allow for an additional 10 percent up to a maximum of 50 percent of the project costs.

Eligibility requirements include being located in New York state and being a customer of a utility that pays into the System Benefit Charge (SBC) fund as well as contributing to the SBC. The CHP system must include black start capability and be designed to provide grid independent operation. The CHP system must have an annual thermal efficiency of 60 percent or more based on the total thermal and power output expressed in Btu divided by the higher heating value (HHV) of the total fuel input. The prime mover of the CHP system must have NO_x emissions of no more than 1.6 lb/MWh. The project must install the necessary instrumentation and data logging equipment and allow the state to monitor the performance of the system for 4 years following commissioning. There are various reports required as well as an engineering level application to solicit funding. The program favors contracting directly with the CHP plant owner rather than a third party or ESCO but exceptions to this rule may be made on a case-by-case basis.

California Standard Interconnection Rule

The California Public Utilities Commission together with the California Energy Commission and the state’s electric utilities developed a statewide standard agreement for interconnection, operation and metering requirements for distributed generation including CHP. This agreement is incorporated into Rule 21 of each investor-owned utility’s tariff and provides for a common specification for interconnection of CHP power generators up to 10 MW with the power grid throughout the state. This harmonization of standards across various utility regions significantly reduces the complexity and time consumption in applying for interconnection resulting in reduced project costs.

Connecticut Renewable Portfolio Standards

The state of Connecticut enacted legislation that requires electricity providers provide a minimum percentage of their retail load using renewable sources of energy. There are three classes of renewable sources with separate minimum percentage requirements for each class. Class III renewables are defined as “the electricity output from combined heat and power systems with an operating efficiency level of no less than 50 percent that are part of customer-side distributed resources developed at commercial and industrial facilities in this state on or after January 1, 2006, a waste heat recovery system installed on or after April 1, 2007, that produces electrical or thermal energy by capturing preexisting waste heat or pressure from industrial or commercial processes, or the electricity savings created in this state from conservation and load management programs begun on or after January 1, 2006.” The minimum percentage of Class III renewables was 2 percent in 2008, is 3 percent in 2009, and goes to 4 percent from 2010 through 2020.

The subject electric power providers must either provide the stated level of CHP power themselves or purchase Class III renewable energy credits from qualified and registered CHP owners which will provide an additional income to the CHP system owner further enhancing the value of the system. Approved Class III credits are equal to at least 1 cent/kWh with the revenue for these credits being divided between the owner and the state Conservation and Load Management Fund. The division will depend on system location, type of customer, and level of state support involved.

The recognition of CHP as a renewable energy resource and, more importantly the monetization of power output from CHP using renewable energy related funds is relatively new but gaining ground. There is some concern among states that the renewable energy portfolio targets already declared may be very difficult and expensive to achieve using only solar, wind, biomass, or other traditional renewable sources. Inclusion of CHP as a renewable source will significantly improve the chances of meeting these targets without adding high costs and also provides for clean energy systems that can produce continuous power regardless of weather conditions. This is particularly true for states that do not have the benefit of high solar insolation or wind resources throughout the year.

German CHP Feed-In Tariff

Germany passed a Cogeneration Act in 2002 that provides production incentive payments for CHP plants (new or refurbished) that feed electricity into the grid. The act provides additional payments for power produced on top of the wholesale market rates and is funded by a levy on residential and industrial electricity users. Payments vary according to type and size of plant and range from over 1 to approximately 2.5 Euro cents/kWh for new and refurbished CHP plants with payments of over 5 Euro cents/kWh for CHP plants under 50 kW or using fuel cells as the prime mover. Payments were originally designed to be progressively reduced and phased out by 2010 but a review of the program in 2006 showed that CO₂ reduction targets resulting from the program would be missed for 2010. This combined with revised and more stringent national greenhouse gas emission reduction targets are expected to lead to an extension of the current program beyond 2010.

Utility Programs

Many utilities in the United States have recently begun to look favorably at CHP as a way to avoid expensive grid upgrades as well as provide their customer base with more options on energy supply. While there has been some reluctance by electric utilities to embrace CHP in the past, many now offer programs that identify efficiency opportunities in client facilities including CHP.

Future Policy Development

Since the PURPA regulations were enacted in 1978 there have not been significant policy changes to assist the development of CHP at the federal level until the recent investment tax credit allowance. In the interval, deregulation of electricity supply and restructuring of the power market led to significant changes in the utility business model as well as customer options on energy supply. States such as California and New York began to develop policies supportive of CHP over the last two decades with more

rapid development coming in the last decade. An electricity supply crisis in California combined with escalating energy costs and rising global warming concerns have prompted a number of U.S. states as well as European countries to try to speed up the pace of CHP adoption within their jurisdiction.

Early measures were often targeted at removing specific barriers to CHP implementation without having coordinated efforts toward removing other barriers. Complexities regarding administration of programs as well as recognition of utility concerns regarding safety and revenue helped to slow progress. In addition, the market for CHP began to shift from large industrial sites to smaller commercial and institutional sites and policy makers needed to come to grips with the effects of restructuring the electric power market. While there was some success at varying levels, many of the barriers to implementation of CHP on a wide scale still existed. Recent efforts have embraced a more coordinated approach between regulators and industry with support from the Department of Energy and recognition of utility concerns eliminating some of the barriers that previously existed. Standard interconnection agreements combined with capital grants and streamlined air permitting procedures have begun to open the market for CHP.

While the situation has improved, barriers such as natural gas price volatility, high expectations by owners on the rate of return on their investment, and the complexity of implementing CHP at a particular site still hold the industry back. Earlier programs also failed to necessarily produce the results expected by those funding the programs. Poor design led to under utilization and lower than expected efficiencies while meeting emissions targets on a continuous basis has also proved difficult.

As the industry continues to try to find ways to avail of the benefits offered by CHP, future policy will need to address remaining barriers where practical as well as encourage further cooperation from utilities who have yet to become a full proponent of CHP. Many U.S. states are currently investigating the potential to decouple utility revenue from power throughput in order to gain stronger utility support for CHP. Such efforts are generally spearheaded by the state utility regulatory authorities and would require legislative policy changes. As with some renewable energy support programs, CHP support may shift toward production payments and measurement and verification models to help ensure that public money invested in CHP does in fact derive the desired results.

Greenhouse gas reduction targets at the federal, regional, and state level will have increased impact as regulators and policy makers begin to recognize the important role to be played by CHP in meeting these targets. Cap and trade programs will support CHP development when displacement of both power and thermal energy use is attributed to CHP. Furthermore, a transition from input-based emissions rating to output-based emissions whereby credit is given for the higher fuel efficiency of CHP prime movers will also allow for easier deployment of CHP.

All these issues are currently in various stages of discussion or development and represent a natural evolution for CHP related policy.

CHP System Requirements

The continually evolving policy efforts by federal, state, and local authorities will have some impact on the design of CHP systems. In general the benefits offered by CHP can only be realized if the system is significantly more efficient than non-CHP options and if the CHP system has a high load factor. CHP systems should have an annual operating

efficiency no less than the PURPA requirements. These issues are more related to site-specific application, design, and proper sizing of equipment than to CHP equipment itself but none the less is a critical element in the future success of CHP.

Capital cost continues to be a significant barrier for wide implementation of CHP. Future CHP systems need to target this area with modular power generation and thermal designs being developed to reduce installed costs as well as increase integration reliability. Acceptable monitoring and data logging equipment will also be required to meet reporting requirements as more incentive programs move toward verifiable production type payments.

Environmental concerns and greenhouse gas emission reduction targets will continue to be a strong motivation for policy makers to support CHP deployment. CHP systems must continue to reduce emissions levels and in many cases will require the addition of exhaust after treatment equipment to show significant gains over conventional technology.

Carbon Footprint— Environmental Benefits and Emission Controls

Dharam V. Punwani

Even though the primary products of all fossil fuel combustion are water vapor and carbon dioxide (CO_2), there are several products of combustion that are considered undesirable for a healthy environment. These include nitrogen oxides (NO_x), carbon monoxide (CO), unburned hydrocarbons (HC), sulfur oxides (SO_x), and particulate matter (PM).

The emissions of undesirable products or pollutants depend on the composition of the fuel used and the type of combustion system deployed and its mode of operation. All the sulfur in the combusted fuel appears in the emissions as SO_x . Total emissions of NO_x consist of the following two components:

1. Fuel NO_x
2. Thermal NO_x

Fuel NO_x correspond to the products of combustion involving the oxidation of nitrogen content of the fuel, while thermal NO_x refer to the products of combustion involving the oxidation of nitrogen in the combustion air. The emissions of thermal NO_x products are independent of the nitrogen content of the fuel but are directly proportional to the temperature of combustion. Higher combustion temperatures result in higher production of thermal NO_x .

The emissions of CO , unburned HC , and PM depend on the air-fuel ratio and the tuning of the combustion system. The emissions of PM depend primarily on the type of fuel used.

Most applications of CHP systems use natural gas or a biogas (produced by biological conversion of waste materials). Fuel oil/diesel, biodiesel are also used for some applications. Since gaseous fuels are used most often in CHP systems and the sulfur content of most gaseous fuels is low, SO_x emissions are generally not a concern for CHP

systems. The use of a solid fuel, such as coal or biomass, for CHP systems, though feasible for some applications, is rare. This chapter primarily discusses emissions of CO₂ and NO_x from reciprocating engines and combustion turbines.

Carbon Footprint of Electric Power Production

Combustion of all fossil fuels results in the emissions of CO₂, which is considered to be a major greenhouse gas (GHG). Many studies have related global warming and climate change to the emissions of CO₂. Significant worldwide efforts are underway to reduce the emissions of CO₂, including those from the use of fossil fuels for electric power production and for providing thermal energy needs.

The average carbon footprint (weight of CO₂ emitted) per unit (MWh) of electric energy produced by remote electric power utilities is different for various states because it depends on the mix of coal, gas, oil, biomass, and nuclear fuels used in that state for power generation. In addition, the carbon footprint of electric power production during peak (nonbaseload) period is generally higher than that during the baseload period. This is because less efficient electric power plants are required to be brought online to meet the peak demand. An example of the difference between the average and peak load periods for some states versus a CHP system is shown in Table 7-1.¹ The table shows that the carbon footprint of a CHP system is significantly lower than those for the average and non-base-load power generation.

The carbon footprint of energy consumed in a specific facility is calculated by multiplying the annual use of each type of energy (electric, gas, fuel oil, etc.) consumed at the facility with the carbon factor assigned/estimated, for that fuel in that region or state, by the U.S. Environmental Protection Agency (EPA). Lists of carbon factors for various sources of energy in various states and regions are available at the Web site of the EPA (www.epa.gov/cleanenergy/) and the information on carbon dioxide and

State	Carbon Dioxide Emissions (lb/MWh) (2004)	
	Average	Nonbaseload
Illinois	1,200	2,200
Indiana	2,100	2,200
Iowa	1,900	2,400
Michigan	1,400	2,000
Minnesota	1,500	2,000
Missouri	1,900	2,100
Ohio	1,800	2,000
Wisconsin	1,700	2,100
CHP system using natural gas	900	900

Source: Kelly, J., "CO₂ Reduction by Distributed Generation," presentation made at the Midwest Cogeneration Association Meeting, Oakbrook Terrace, IL, March 2008.

TABLE 7-1 Comparison of CHP Carbon Footprint versus Average and Nonbaseload Electric Power Generation

other emissions for a number of industries are available at Web site of the World Business Council for Sustainable Development (www.ghgprotocol.org).

Greenhouse Gas Emission Calculators

Several GHG emission calculators are available. Some of these calculators are discussed below. The scope of these calculators varies from very general and basic calculations to a variety of more complex calculators for business and industrial sectors. These calculators can be used for estimating baseline emissions of GHG for the existing facilities as well as for the potential GHG emissions from the fuel consumed if the facility considers using a CHP system. These calculators, however, do not estimate the fuel consumed by a CHP facility. These estimates have to be made separately using other tools discussed in Chap. 8.

U.S. EPA GHG Equivalency Calculator

The *U.S. EPA GHG Equivalency Calculator*, developed by for the U.S. Environmental Protection Agency, is available at <http://www.epa.gov/cleanenergy/energy-resources/calculator.html>. It can be used for estimating emissions from the use of purchased electricity and natural gas. It uses the factor of 7.12×10^{-4} metric tons CO₂ per kWh, which is the 2005 U.S. national average emission during nonbaseload operations. For emissions in subregions during nonbaseload as well as baseload periods, the use of the eGRID Web site (<http://www.epa.gov/cleanenergy/energy-resources/egrid/index.html>) is recommended. The basis used for GHG emissions from using natural gas is 5×10^{-3} metric tons of CO₂ per therm. It assumes average heat content of natural gas is 100,000 Btu/therm and that its carbon content is 14.47 kg/10⁶ Btu and that combustion is 100 percent complete.

U.S. EPA Office Carbon Footprint Calculator

The *U.S. EPA Office Carbon Footprint Calculator*, developed in 2008, is applicable to a variety of office sizes, locations, and types. It not only estimates emissions, it also provides suggestions for reducing emissions of GHG. It can be used for benchmarking and performance improvements. It accounts for emissions from three types of sources:

1. Owned or controlled by the business
2. Purchased electricity, heat, and/or steam
3. Indirect sources such as waste disposal and purchased materials

This calculator can be downloaded from the following URL: www.epa.gov/epawaste/partnerships/wastewise/carboncalc.htm.

Clean Air Cool Planet Campus GHG Calculator

The *Clean Air Cool Planet Campus GHG Calculator* is designed to aid schools that have completed greenhouse gas inventories in developing their long-term, comprehensive climate action plans based on those inventories. It facilitates analysis of carbon reduction options, project payback times, net present value, cost per ton reduced, and other relevant markers. This calculator can be downloaded from the following URL: <http://www.cleanair-coolplanet.org>.

World Resources Institute's Industry and Office Sector Calculator

The *World Resources Institute's (WRI's) Industry and Office Sector Calculator* has been developed in partnership with the Business Council for Sustainable Development.

This calculator is widely used internationally by government and business leaders to understand, quantify, and manage greenhouse gas emissions. It provides the accounting framework for nearly every GHG standard and program in the world—from the International Standards Organization to The Climate Registry—as well as hundreds of GHG inventories prepared by individual companies. It can be downloaded from <http://www.ghgprotocol.org/calculation-tools/sector-toolsets>.

Environmental Benefits of CHP

As discussed in previous chapters, use of a CHP system improves the energy efficiency of natural gas utilization to as much as 85 percent compared to the approximately 50 percent energy efficiency of a conventional approach of buying electric energy from the grid and using a conventional boiler for providing the thermal energy needs. Therefore, for this example, the CHP system is 70 percent more energy efficient than the conventional system and will thus, reduce carbon dioxide emissions by 70 percent.

As shown earlier in Table 7-1, the use of CHP can significantly reduce the carbon emissions or “eco-footprint” when compared to those from the average and nonbase-load electric generation. Estimates¹ in Table 7-2 show that the use of CHP in a commercial building (2.6 million square feet) located in New York, NY could reduce annual emissions of CO₂ by about 16,800 metric tons.

According to the U.S. Energy Information Administration and EPA’s eGRID, the total installed capacity of CHP systems in the United States is about 85 GW and accounts for only 9 percent of the total U.S. electric power generation in 2006.² According to a report³ of the Oak Ridge National Laboratory, these CHP systems help reduce annual energy consumption by 1.9 quads and reduce annual CO₂ reduction by 248 metric tons (or about 68 metric tons of carbon). This quantity of reduction in CO₂ emissions is equivalent to removing 45 million cars off the road. If in the future, the United States received 20 percent of its electricity capacity from CHP, it would be equivalent to removing more than 154 million cars (or more than half of the U.S. vehicle fleet) from the roads. If the installed capacity of CHP reaches 20 percent mark in 2030, the total installed capacity would be about 241 GW. It will reduce annual energy consumption by 5.3 quads and reduce annual CO₂ emissions by 848 metric tons (or about 231 metric tons of carbon).

Source	CO ₂ Emissions (metric tons)		CO ₂ Emissions Reduction (metric tons)
	2004 Baseline	CHP System	
On-peak electricity	34,400	8,000	26,400
Baseload electricity	3,700	3,700	0
Steam	6,300	4,600	1,700
Natural gas	0	11,300	–11,300
Total	44,400	27,600	16,800

Source: Kelly, J., “CO₂ Reduction by Distributed Generation,” presentation made at the Midwest Cogeneration Association Meeting, Oakbrook Terrace, IL, March 2008.

TABLE 7-2 Carbon Footprint Reduction Impact of Using CHP in a Commercial Building in New York, NY

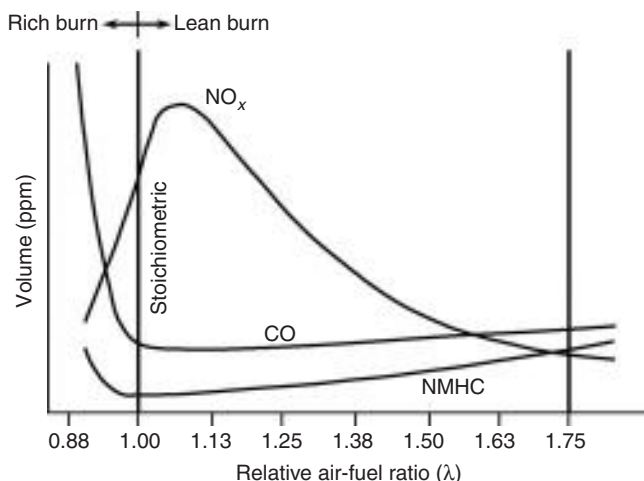


FIGURE 7-1 Effect of air-fuel ratio on emissions of natural gas-fired engine.

According to the 2007 study⁴ by McKinsey & Company on reducing U.S. GHG emissions shows, CHP not only helps reduce GHG emissions, it achieves these reductions with economic advantages over many other environment friendly technologies (see Fig. 7-1). It shows that CHP can deliver CO₂ reductions at a negative marginal cost for both the commercial and industrial sectors. This means that investing in CHP generates positive economic return over the technology's life cycle.

Lower emissions of carbon dioxide, that is, smaller carbon footprint, for power production by CHP system, may also contribute to the economic incentive for implementing CHP. Governments around the world are at various stages of limiting the emissions of CO₂ by providing economic incentives for the reduction of this GHG. One of the incentives is to allow commercial trading of CO₂ emissions. Trading of CO₂ emissions allows a company that implements a new technology for reducing the emissions of CO₂ to sell the CO₂ reductions achieved by the new technology to another company that is required to reduce emissions of CO₂ but cannot yet implement a new technology for doing so.

Carbon emissions' trading has been steadily increasing in recent years. According to information attributed to the World Bank's Carbon Finance Unit, approximately 374 million metric tons of carbon dioxide equivalent (mtCO₂e) were exchanged through projects in 2005, a 240 percent increase relative to 2004 (110 mtCO₂e)⁵ which was itself a 41 percent increase relative to 2003 (78 mtCO₂e).⁶ According to the World Bank estimates the size of the carbon market was U.S. \$11 billion in 2005, U.S. \$30 billion in 2006, and U.S. \$64 billion in 2007.⁷

Environmental Emissions from CHP

Emissions of CO₂, NO_x, and SO_x from CHP systems depend primarily on three factors:

1. Fuel type and quality
2. Power generation technology
3. Emission control technology used for the prime mover deployed for power generation

Ranking of the various fuels in terms of their emissions production potential, in the order of the *least to the highest* emissions is as follows: natural gas, biogas, diesel/fuel oil No. 2, and coal. Similar ranking of the various CHP power generation technologies in terms of their emissions production potential is as follows: fuel cells, combustion turbines, microturbines, natural gas-fired engines, diesel engines, and coal-fired boilers. Therefore, the use of natural gas in fuel cells produces the least emissions, while the use of coal in boilers to produce steam for use in steam turbines to produce power produces the most emissions.

Emissions of Reactive Organic Gases

In addition to the emissions of CO_2 , CO, NO_x , and SO_x , environmental permitting process also requires estimates of other criteria pollutants, such as trace organic compounds, as discussed in Chap. 13. The reactive organic gases (ROGs), also known as volatile organic compounds (VOCs), are estimated by the sum of all the speciated organic compounds minus those that are methane and ethane.

Examples of uncontrolled emissions, including ROGs/VOCs, for four-stroke rich and lean burn engines can be found at the following link:⁸ <http://www.epa.gov/ttn/chief/ap42/ch03/final/c03s02.pdf> (see Ref. 8).

Emissions Calculator

The Midwest CHP Application Center has developed a simple spreadsheet-based emissions calculator.⁹ The emissions calculator estimates expected emissions from the various classes of power generation technologies (i.e., natural gas-fired reciprocating engines and natural gas-fired turbines) used in CHP systems. The emissions calculator does not provide an estimate of emissions from any specific manufacturer's model of the power generator. For emission estimates for a specific manufacturer model, please refer to the manufacturer's specification sheet for that piece of equipment.

The emissions calculator utilizes the AP-42 emission factors compiled by the U.S. EPA and can be downloaded from the following URL: http://www.chpcentermw.org/pdfs/030123-PermitGuidebook-EmCalc_IL.xls. It allows approximation of the expected emissions from five power generation technology classes:

1. Diesel engine less than 600 hp
2. Diesel engine greater than 600 hp
3. Natural gas-fired engine
4. Gasoline-fired engine less than 250 hp
5. Natural gas-fired turbine

Table 7-3 shows samples of the emissions calculator's results for the above prime movers. The left side of the table shows the information for the case when the prime mover is planned to be located in an attainment area. The various columns display the following:

- The first column shows the pollutants being estimated.
- The second column provides the AP-42 emission factors utilized by this emissions calculator.
- The third column provides the estimated emission levels in tons per year for each pollutant, taking into account the operating hours per year and the fuel input.

CHP Emissions Calculator

Diesel Recip Engine < 600 hp	
CHP Operation per Year (h):	3,400
Engine Output (hp):	500.00

Attainment					Nonattainment				
Pollutant	Emissions Factor* (lb/hp · h)	Emissions (tpy)	PSD Major Modification Significant Level (tpy)	PSD Major Source Thresholds [†] (tpy)	Pollutant	Emissions Factor* (lb/hp · h)	Emissions (tpy)	Nonattainment NSR Major Modification Significant Level (tpy)	Nonattainment NSR Major Source Thresholds (tpy)
PM	0.002200	1.87	15	250 [†]	PM - McCook, Lake Calumet, Granite City	0.002200	1.87	15	100
SO _x	0.002050	1.74	40	250 [†]	VOM - Metro East	0.002514	2.14	40	100
NO _x	0.031000	26.35	40	250 [†]	NO _x - Metro East	0.031000	26.35	40	100
VOM	0.002514	2.14	40	250 [†]	VOM - Chicago	0.002514	2.14	25	25
CO	0.006680	5.68	100	250 [†]					

*Emissions factors for small diesel engines—uncontrolled emissions.

[†]Emissions factors exclude 28 categories of source.

TABLE 7-3 Sample of CHP Emissions Calculator Results (*Continued*)

Diesel Recip Engine >= 600 hp	
CHP Operation per Year (h):	3,400
Engine Output (hp):	4000.00

Attainment					Nonattainment				
Pollutant	Emissions Factor* (lb/hp · h)	Emissions (tpy)	PSD Major Modification Significant Level (tpy)	PSD Major Source Thresholds (tpy)	Pollutant	Emissions Factor* (lb/hp · hr)	Emissions (tpy)	Nonattainment NSR Major Modification Significant Level (tpy)	Nonattainment NSR Major Source Thresholds (tpy)
Uncontrolled Emissions					Uncontrolled Emissions				
PM	0.000700	4.76	15	250 [†]	PM - McCook, Lake Calument,Granite City	0.000700	4.76	15	100
SO _x	0.008090	55.01	40	250 [†]	VOM - Metro East	0.000642	4.37	40	100
NO _x	0.024000	163.20	40	250 [†]	NO _x - Metro East	0.024000	163.20	40	100
VOM	0.000642	4.37	40	250 [†]	VOM - Chicago	0.000642	4.37	25	25
CO	0.005500	37.40	100	250 [†]					
Controlled Emissions					Controlled Emissions				
NO _x	0.013000	88.40	40	250 [†]	NO _x - Metro East	0.013000	88.40	40	100

*Emissions factors for large stationary diesel engines—uncontrolled emissions.

[†]Emissions factors exclude 28 categories of source.

Natural Gas–Fired Turbine	
CHP Operation per Year (h):	6,000
Fuel Input (MMBtu/h):	90.00

Attainment					Nonattainment				
Pollutant	Emissions Factor* (lb/MMBtu Fuel Input)	Emissions (tpy)	PSD Major Modification Significant Level (tpy)	PSD Major Source Thresholds (tpy)	Pollutant	Emissions Factor* (lb/MMBtu Fuel Input)	Emissions (tpy)	Nonattainment NSR Major Modification Significant Level (tpy)	Nonattainment NSR Major Source Thresholds (tpy)
Uncontrolled Emissions					Uncontrolled Emissions				
PM	0.006600	1.78	15	250 [†]	PM - McCook, Lake Calument,Granite City	0.006600	1.78	15	100
SO _x	0.003400	0.92	40	250 [†]	VOM - Metro East	0.002100	0.57	40	100
NO _x	0.320000	163.20	40	250 [†]	NO _x - Metro East	0.320000	86.40	40	100
VOM	0.002100	0.57	40	250 [†]	VOM - Chicago	0.002100	0.57	25	25
CO	0.082000	22.14	100	250 [†]					
Formaldehyde	0.000710	0.19	10	10					
With Water-Steam Injection					With Water-Steam Injection				
NO _x	0.130000	35.10	40	250 [†]	NO _x - Metro East	0.130000	35.10	40	100
CO	0.030000	8.10	100	250 [†]					
With Lean-Premix					With Lean-Premix				
NO _x	0.099000	26.73	40	250 [†]	NO _x - Metro East	0.099000	26.73	40	100
CO	0.015000	4.05	100	250 [†]					

*Emissions factors for stationary gas turbines—uncontrolled emissions.

[†]Emissions factors exclude 28 categories of source.

TABLE 7-3 Sample of CHP Emissions Calculator Results (*Continued*)

Natural Gas–Fired Engine									
CHP Operation per Year (h): 8,760									
Fuel Input (MMBtu/h): 18.00									
Attainment					Nonattainment				
Pollutant	Emissions Factor* (lb/MMBtu Fuel Input)	Emissions (tpy)	PSD Major Modification Significant Level (tpy)	PSD Major Source Thresholds (tpy)	Pollutant	Emissions Factor* (lb/MMBtu Fuel Input)	Emissions (tpy)	Nonattainment NSR Major Modification Significant Level (tpy)	Nonattainment NSR Major Source Thresholds (tpy)
PM	0.009910	0.78	15	250 [†]	PM - McCook, Lake Calument, Granite City	0.009910	0.78	15	100
SO _x	0.000588	0.05	40	250 [†]	VOM - Metro East	0.118000	9.30	40	100
NO _x	0.847000	66.78	40	250 [†]	NO _x - Metro East	0.847000	66.78	40	100
VOM	0.118000	9.30	40	250 [†]	VOM - Chicago	0.118000	9.30	25	25
CO	0.557000	43.91	100	250 [†]					
Formaldehyde	0.052800	4.16	10	10					

*Emissions factors for four stroke lean burn engines—uncontrolled emissions.

[†]Emissions factors exclude 28 categories of source.

Recip Engine Gasoline < 250 hp	
CHP Operation per Year (h):	3,400
Engine Output (hp):	200.00

Attainment					Nonattainment				
Pollutant	Emissions* Factor (lb/hp · h)	Emissions (tpy)	PSD Major Modification Significant Level (tpy)	PSD Major Source Thresholds (tpy)	Pollutant	Emissions* Factor (lb/hp · h)	Emissions (tpy)	Nonattain- ment NSR Major Modification Significant Level (tpy)	Nonattainment NSR Major Source Thresholds (tpy)
PM	0.000721	0.25	15	250 [†]	PM - McCook, Lake Calument, Granite City	0.000721	0.25	15	100
SO _x	0.000591	0.20	40	250 [†]	VOM - Metro East	0.021591	7.34	40	100
NO _x	0.011000	3.74	40	250 [†]	NO _x - Metro East	0.011000	3.74	40	100
VOM	0.021591	7.34	40	250 [†]	VOM - Chicago	0.021591	7.34	25	25
CO	0.439000	149.26	100	250 [†]					

*Emissions factors gasoline fired engines—uncontrolled emissions.

[†]Emissions factors exclude 28 categories of source.

TABLE 7-3 Sample of CHP Emissions Calculator Results (*Continued*)

- The fourth column provides the threshold levels for sites that are considered major modifications to existing sources.
- The fifth column provides the threshold levels for sites that are considered new major sources.

The right side of the printout provides similar information for the case when the prime mover is located and operated in a nonattainment area.

It should be noted that the emissions calculator only calculates the emissions for the selected pollutants, which may be critical for CHP facilities. However, emission limits for other pollutants have to be observed as well.

Emission Control Technologies for CHP

Emissions of CO₂ from CHP systems are not presently controlled and depend primarily on the type and quality of fuel used. Except for coal, gaseous fuels used most often in CHP systems are quite low in sulfur and generally do not require post-combustion treatment to reduce SO_x. The emission control technologies for CHP systems control the emissions of NO_x, CO, and unburned hydrocarbons. The applications of these technologies depend on the type of prime mover deployed for power generation.

Reciprocating Internal Combustion Engines

As discussed in Chap. 3, two types of ignition systems are used in four-stroke reciprocating internal combustion engines (IC engine): spark ignition and compression ignition. Spark-ignited engines can use natural gas, biogas, propane, or gasoline as fuel where as compression-ignited engines can only use diesel, biodiesel, or a combination of diesel and natural gas.

IC engines are designed to operate in one of the two modes:

1. Rich burn
2. Lean burn

Typical effect of rich and lean burn operation of IC engines on the emissions¹⁰ is shown in Fig. 7-1.

Rich burn operations use fuel-air ratios (or the inverse of the air-fuel ratios) that are higher (or the air-fuel ratios are lower) than the stoichiometric ratio (defined as the fuel-air ratio theoretically required for complete combustion of the fuel). Generally, rich burn mode is more common for engine capacities <500 kW (670 hp). Emissions of NO_x from rich burn engines are in the range of 30 to 50 lb/MWh (or 625 to 1060 ppm at 15 percent oxygen). In order to put the emissions of engines in some perspective, it is important to note that the average emissions from all central power plants in the United States are approximately 3 lb of NO_x per MWh according to the EPA eGRID data for the year 2000.¹¹ The emissions from rich burn engines are generally not acceptable at most locations especially in Europe and in the United States. Therefore, most installations using rich burn engines require post-combustion treatment of exhaust gases.

Exhaust from rich burn engines is generally treated by a three-way catalyst. A three-way catalytic converter accomplishes the following three simultaneous tasks:

1. Reduction of nitrogen oxides to nitrogen and oxygen: $2\text{NO}_x \rightarrow x\text{O}_2 + \text{N}_2$
2. Oxidation of carbon monoxide to carbon dioxide: $2\text{CO} + \text{O}_2 \rightarrow 2\text{CO}_2$

3. Oxidation of unburnt hydrocarbons (C_xH_y) to carbon dioxide and water:

$$2C_xH_y + (2x+y/2)O_2 \rightarrow 2xCO_2 + yH_2O$$

The efficiency of a three-way catalyst system for reducing emissions of NO_x and CO is in the range of 85 to 95 percent, depending on the exhaust gas temperature, air-fuel ratio, and catalyst volume. A three-way catalyst can reduce NO_x emissions to as low as 0.5 lb/MWh.¹¹

Some examples of the installed and operating costs and cost-effectiveness (cost of removing 1 ton of NO_x) of three-way catalyst systems for engine capacities ranging from 250 to 4000 kW are shown in Table 7-4.

Lean burn operations use fuel-air ratios that are lower than the stoichiometric ratio. The energy efficiency of lean burn engines is slightly higher than those for the rich burn engines. Without any treatment of the exhaust gases, NO_x emissions from lean burn engines are in the range of 2 to 6 lb/MWh (42 to 127 ppm at 15 percent oxygen). Many installations using lean burn engines do *not* require exhaust treatment. If exhaust treatment is needed to reduce NO_x emissions, the most common treatment is the use of selective catalytic reduction (SCR).

An SCR system selectively reduces NO_x emissions by injecting ammonia (either in the form of liquefied anhydrous ammonia or aqueous ammonium hydroxide) into the exhaust gas upstream of the catalyst. NO_x , ammonia (NH_3), and oxygen (O_2) in the air react on the surface of the catalyst to form nitrogen (N_2) and water (H_2O). For the SCR system to operate properly, the exhaust gas must be within a particular temperature range (typically between 450 and 850°F).¹² The temperature range is dictated by the selected catalyst surface characteristics where reactions occur. Typically these catalysts are manufactured from noble metal oxides of vanadium or titanium, or from a zeolite. SCR is most effective for engines operating at constant loads. At variable loads, it is less effective and some of the ammonia might go through the system unreacted. This is known as ammonia slip and is regulated by many local air-quality management agencies.

An SCR treatment system has the potential to reduce NO_x emissions from natural gas-fired, diesel-fired, and dual-fuel lean burn reciprocation engines by up to 90 percent. Some examples of the installed and operating costs and cost-effectiveness (cost of removing 1 ton of NO_x) for SCR treatment systems for engine capacities ranging from 250 to 4000 kW are shown in Table 7-4.

In some applications, it might be necessary to reduce emissions of CO in the exhaust of lean burn engines. It is accomplished by catalytic oxidation of the exhaust gases. In a

Engine Capacity (kW)	Installed Cost (\$)		Annual Operating Cost (\$)		Cost Effectiveness (\$/ton) of NO_x Removed	
	Three-Way Catalyst	SCR	Three-Way Catalyst	SCR	Three-Way Catalyst	SCR
250	20,000	310,000	10,000	140,000	290–310	4,380–4,810
1,000	42,000	340,000	27,000	180,000	200–220	1,320–1,490
4,000	130,000	470,000	96,000	310,000	180–190	580–660

Source: EPA (July 1993); Combined Heating, Cooling, and Power Handbook (2002).

TABLE 7-4 Examples of Installed and Operating Costs, and Cost-Effectiveness of Emission Control Technologies Commercially Available for Reciprocating Engines

catalytic oxidation system, when CO passes over a catalyst, usually a noble metal, it is oxidized to CO_2 at efficiencies of up to 90 percent. A catalytic converter also oxidizes unburned or partially burned hydrocarbons and produces CO_2 and H_2O . This type of exhaust gas treatment is generally used for engines fueled by diesel.

Combustion Turbines

As stated earlier, emissions from combustion turbines without exhaust gas treatment are lower than those from reciprocating engines. As discussed in Chap. 3, there are three classes of combustion turbines: aero-derivative, stationary or industrial, and microturbines. Emissions from microturbines (30 to 400 kW) are slightly higher than those resulting from operation of larger-capacity aero-derivative and industrial turbines. Without exhaust gas treatment, NO_x emissions from combustion turbines range from approximately 25 to 120 ppm (by volume) with conventional burners.

There are two options for reducing NO_x emissions from combustion turbines:

1. Combustion system modifications
2. Post-combustion exhaust gas treatment

Combustion System Modifications

The primary objective of combustion system modifications is to reduce the production of thermal NO_x , which increases with increase in peak combustion temperature, residence time and pressure. There are two primary approaches commercially used in this technology category:

1. Water/steam injection
2. Dry low NO_x combustion

In the water/steam injection approach, water or steam is injected into the combustion chamber during combustion. Water or steam injection reduces NO_x production by reducing the peak combustion temperature. In addition to reducing NO_x production, steam injection also increases the mass flow rate of the hot products of combustion entering the turbine and increases its power output without increasing the load of the air compressor (which uses about two-thirds of the turbine output). This emission control technology can reduce NO_x emissions by 70 to 90 percent of that without water/steam injection.

The use of dry low NO_x (DLN) combustion technology has become a primary goal in recent development efforts for combustion turbines. This category of technology uses various options of premixing the fuel and combustion air. Traditional combustion takes place within diffusion flames, where mixing and combustion takes place simultaneously resulting in high temperature peaks and correspondingly high thermal NO_x . Premixing serves to reduce the peak temperatures and residence time. Several patented DLN technologies have now become commercially available with proven NO_x emission results in the range of 15 to 25 ppm (at 15 percent O_2), even though NO_x emissions as low as 5 ppm have been reported. One DLN combustor has the potential of reducing NO_x emissions by as much as 90 percent as shown in Fig. 7-2.

Furthermore the beneficial effect of premixing (DLN) on the emissions of NO_x and CO for natural gas and fuel oil are also shown in Figs. 7-3 and 7-4, respectively.

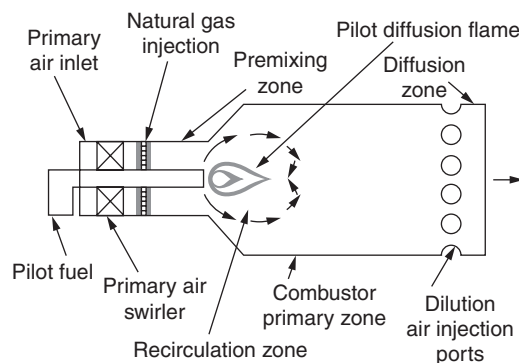


FIGURE 7-2 Example of a DLN combustor concept. (Courtesy of Solar Turbines Inc.)

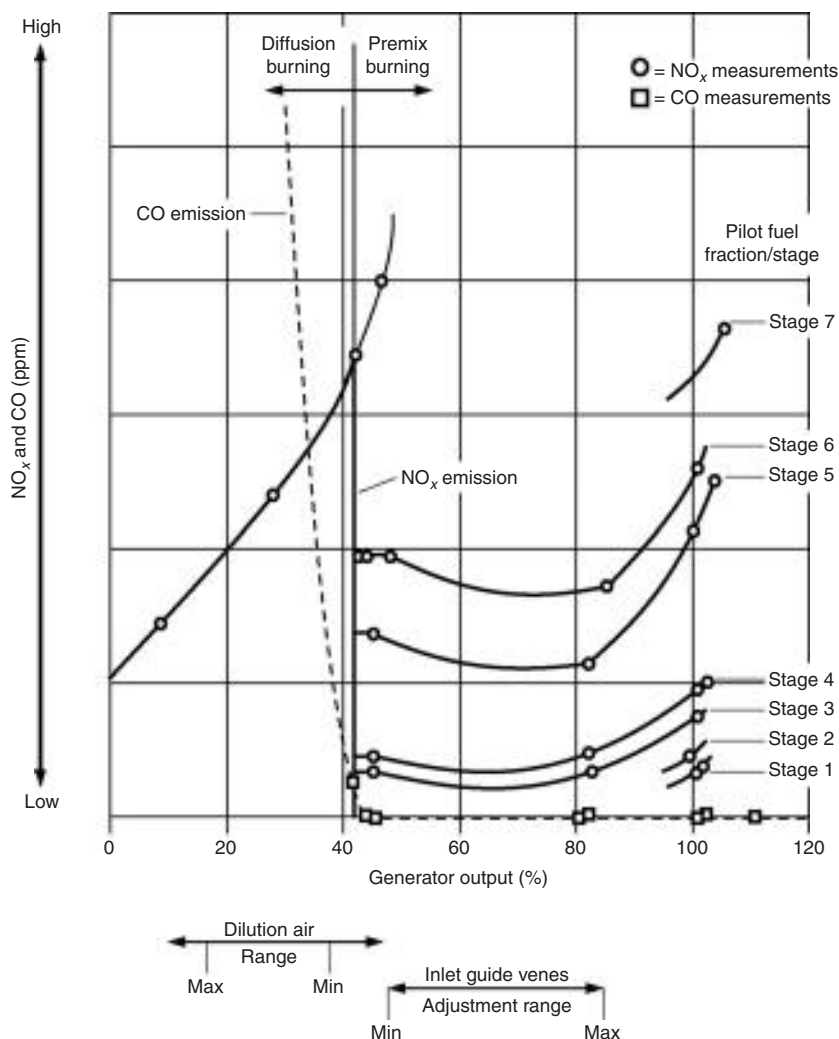


FIGURE 7-3 Examples of emissions from a DLN combustor operating on natural gas. (Courtesy of Siemens Power Corp.)

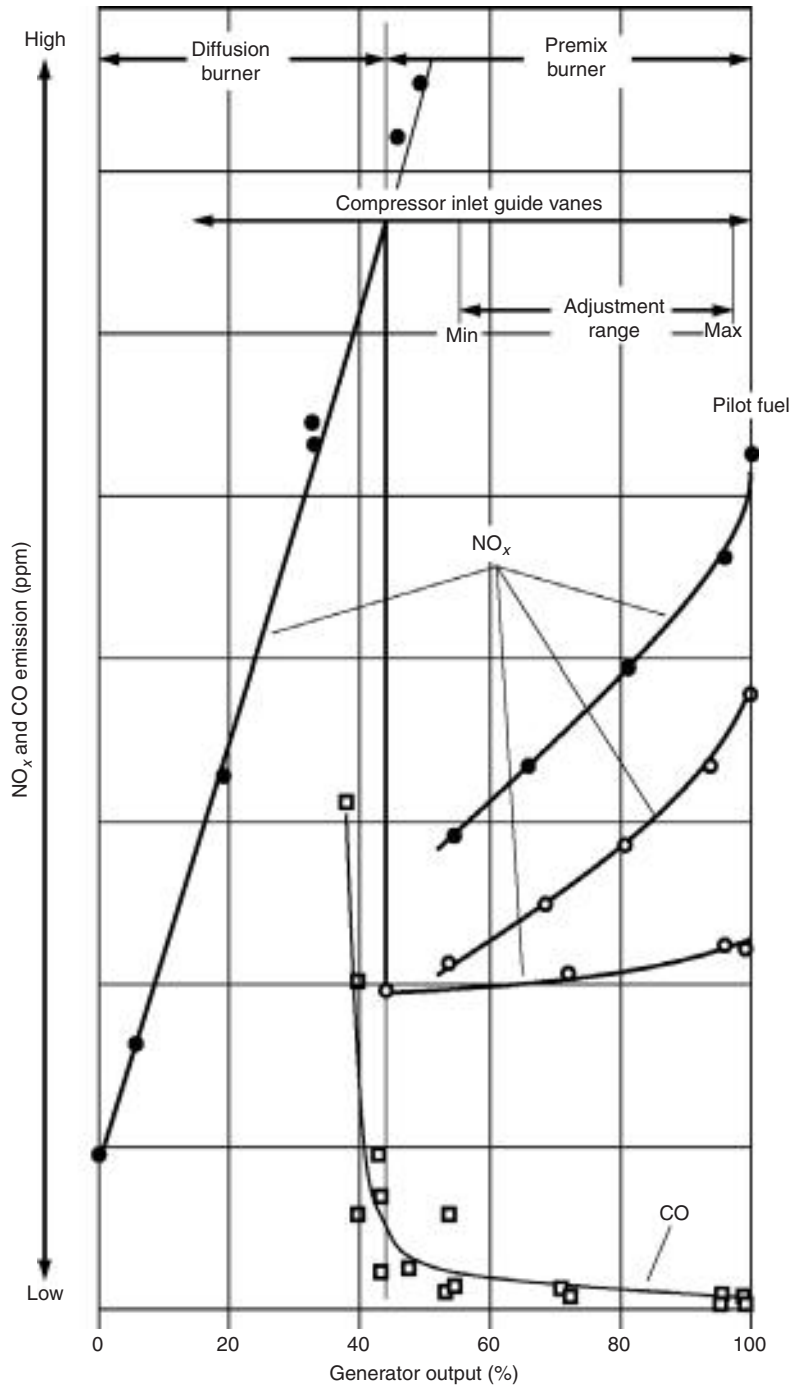


FIGURE 7-4 Examples of emissions from a DLN combustor operating on fuel oil. (Courtesy of Siemens Power Corp.)

Emission Control Technology	Combustion Turbine Capacity (MW)				
	5 Continuous	25 Continuous	100 Continuous	25 Peaking	100 Peaking
Water Injection					
Installed cost (\$)	544,000	1,140,000	2,560,000	1,140,000	2,560,000
Annual operating cost (\$)	165,000	408,000	1,180,000	248,000	624,000
Cost-effectiveness (\$/ton)	1,390–1,780	690–880	500–640	1,670–2,150	1,050–1,350
Steam Injection					
Installed cost (\$)	710,000	1,161,000	3,900,000	1,610,000	3,900,000
Annual operating cost (\$)	185,000	448,000	1,250,000	319,000	813,000
Cost-effectiveness (\$/ton)	1,560–2,000	760–970	520–670	2,150–2,760	1,370–1,760
DLN					
Installed cost (\$)	482,000	1,100,000	2,400,000	1,100,000	2,400,000
Annual operating cost (\$)	63,400	145,000	316,000	258,000	316,000
Cost-effectiveness (\$/ton)	530–800	240–370	130–200	980–1,470	530–800
SCR					
Installed cost (\$)	572,000	1,540,000	3,300,000	1,540,000	3,300,000
Annual operating cost (\$)	258,000	732,000	2,190,000	517,000	1,430,000
Cost-effectiveness (\$/ton)	2,180–2,450	1,230–1,390	920–1,030	3,480–3,920	2,400–2,700

Source: Combined Heating, Cooling, and Power Handbook (2002).

TABLE 7-5 Examples of Installed and Annual Operating Costs and Cost-Effectiveness for Emission Control Technologies Commercially Available for Combustion Turbines

Some examples of the installed and operating costs and cost-effectiveness (cost of removing 1 ton of NO_x) of water injection, steam injection, and DLN are shown in Table 7-5 for various capacities of combustion turbine for continuous and peaking operations.

Post-Combustion Treatment

In this technology category, selective catalytic reduction (SCR), as discussed earlier under reciprocating engines, is also used for treating exhaust gases from combustion turbine systems. A typical process-flow diagram of an SCR system for a gas turbine is shown in Fig. 7-5 and some examples of the installed and operating costs and cost-effectiveness (cost of removing 1 ton of NO_x) of SCR are shown in Table 7-5 various capacities of combustion turbine for continuous and peaking operations.

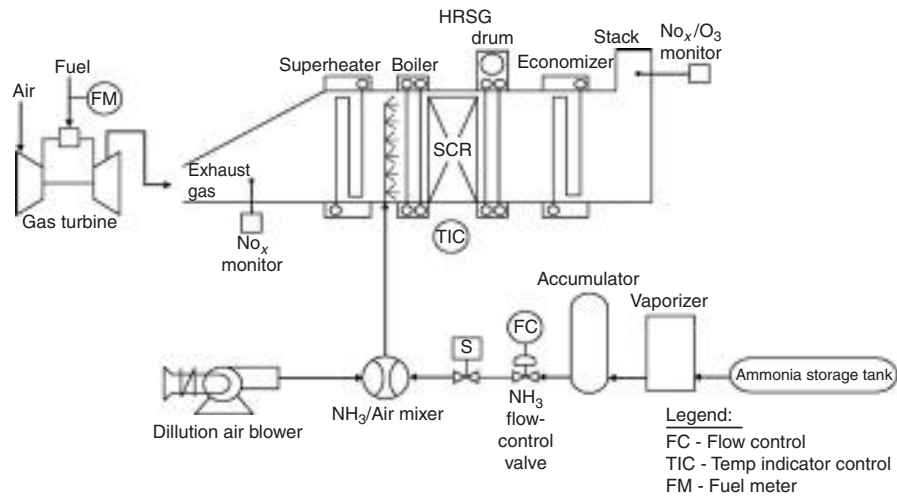


FIGURE 7-5 Typical process-flow diagram for an SCR system for combustion turbine. [Source: Combined Heating, Cooling, and Power Handbook (2002).]

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PART 2

The Feasibility Study

CHAPTER 8

Fundamental Concepts

CHAPTER 9

CHP Economic Analysis

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Fundamental Concepts

Itzhak Maor

T. Agami Reddy

Types of Studies—Screening to Detailed Feasibility

Successful on-site CHP projects require careful evaluation of the feasibility of the CHP system to the site under investigation. The process of performing the feasibility study for a CHP is a phased process starting from a preliminary screening study and ending with a detailed and comprehensive study. A feasibility study essentially consists of (1) obtaining information on existing or proposed facilities including electrical, heating, and cooling load data; (2) developing technically feasible solutions to effectively and efficiently meet the facility's load requirements; and (3) conducting economic analysis which involves calculating estimated energy usage and cost, preparing budget cost estimates, and calculating life-cycle costs to determine the recommended plant size and configuration. The various phases in a feasibility study are shown in Table 8-1, while Table 8-2 provides an indication of the time, effort, information required, and typical cost.

The feasibility study types shown in Tables 8-1 and 8-2 are typical for existing installations and are discussed in more detail in the next sections. For new installations, the integration of a CHP system is like any other mechanical and electrical system (such as hybrid chiller plants and air side systems). The feasibility of CHP systems in new installations should be part of the project design process, which is typically performed during the programming or planning stage. With the increasing availability and popularity of building energy simulation programs (e.g., DOE 2.1, eQuest, and TRACE), the applicability and cost-effectiveness of CHP systems can be evaluated in the early stages of the design. The end of this chapter elaborates the procedure of analyzing a CHP system for new construction.

Tools and Software for Feasibility Study

As discussed in previous chapters, detailed sizing of CHP systems is often not straightforward since it involves considering the variability and concurrent occurrence of thermal (heating and cooling) loads as well as electric demand, along with plant-level equipment performance specifics and the time-variant electric and gas price signals.

Phases	Purpose
Screening, scope, qualification	To determine if the site is a good candidate for a CHP system
Preliminary—Level 1	To determine whether a CHP is technically appropriate and has economic potential
Detailed, comprehensive—Level 2	Use verified data to optimize and refine the results of Level 1 study. This includes: optimal equipment sizing, configuration, application, operation, costing, etc.

TABLE 8-1 Types of Feasibility Studies

Feasibility Study Phases	Time Frame	Information Required	Typical Cost
Screening, scope, qualifications	30 minutes	Minimal site information, average utility costs	None
Preliminary—Level 1	4–6 weeks	1–2 years utility data, building operation, building loads (HVAC, thermal, process), future plans, future equipment replacements, projected energy costs, etc.	\$1,000–\$10,000
Detailed, comprehensive—Level 2	1–4 months	Level 1 study with enhanced modeling, and costing	\$10,000–\$100,000 depending on size and complexity

Source: Values taken from U.S. Environmental, Protection Agency—Combined Heat and Power Partnership—CHP Development Handbook.

TABLE 8-2 Resources Required for Different Feasibility Study Types

Further, there are several feasible equipment and system configurations, and the best among them has to be selected while considering issues of uncertainty and variability over time of many of the inputs. Two general types of programs have been developed: those meant for a preliminary feasibility analysis, and those meant for a comprehensive system design detailed enough for final decision making. The level of inputs and the type of detail necessary to specify equipment and systems for both objectives are obviously widely different.

Most of the simulation programs developed to date pertain to sizing of CHP systems. This section categorizes and briefly describes the primary types of design tools available. Because of the variability of the thermal and electric loads and the distinct possibility that a cost-effective system may be one which is sized for intermediate loading (i.e., neither base load nor peak sized), the design of CHP systems requires evaluation of various system configurations and scenarios which is best done on a computer. The three types of design tools are discussed below.

Manuals and Nomograms for Coarse Screening (or Preliminary Feasibility Evaluation)

Turner (2006) identifies a number of specific manuals and references, which allow simplified sizing of CHP systems. Two studies of special mention are those by Hay (1988) and Oven (1991) which use thermal and electric load duration curves for system sizing. This approach has also been adopted and illustrated by Orlando (1996) for two detailed case study examples. Caton and Turner (1997) have developed a methodology for sizing CHP plants for small industrial applications. Somasundram et al. (1988) proposed a simple screening method to determine the economic feasibility of small-scale cogeneration systems. Available billing data for electricity and gas use and cost are needed for the “go or no-go” evaluation, which is determined from interlinked set of figures or nomograms. Three nomograms have been developed (one for engine sizes > 400 kW, for engine sizes 100 to 400 kW, and for engine sizes 20 to 100 kW) and five illustrative case studies have been provided.

Fischer and Glazer (2002) and Fischer (2004) suggest a simple method involving the development of a closed-form equation to determine the savings factor from a CHP system. This approach is meant for any energy manager wishing to evaluate the feasibility of a CHP system for his facility. It uses information such as (a) facility utility bills, (b) utility rate structure, (c) building and system parameters and performance measures such as recoverable waste heat, chiller COP, ratio of thermal-electric loads, and (d) equipment costs. Numerical values associated with these factors are used to solve an analytical expression using a handheld calculator, and thereby deduce the simple payback. Another closed-form method for early feasibility analysis has also been proposed by Beyene (2002).

Knowledge-based system design approaches have also been proposed in conjunction with the technical design. Hughes et al. (1996) propose a methodology wherein the inherent risk and uncertainty in the proper design of CHP systems are better handled in terms of decision analysis techniques rather than traditional economic models, and illustrate the approach with a case study. Williams et al. (1998) propose a computerized decision support tool to aid engineers in selecting the optimal CHP system. The program can accommodate different types of inputs depending on the type of information available: option 1 being an initial assessment where only the type, size, and location of the building are known, going up to option 4, where actual measured heat and power profiles are used to size the CHP system. A commercial interval analysis tool called EconExpert-IAT (Competitive Energy Insight 2006), driven by Excel-based spreadsheets, has also been developed which performs an automated simulation of the economics (discounted cash flows) associated with energy purchases, and on-site power generation using DG/CHP or energy management projects. This tool requiring interval data (at 15 minutes, 30 minutes, or hourly time scales) uses an existing building load profile database called EnergyShape (which was originally developed by EPRI).

Software Screening Tools

Programs in this category require only monthly thermal and electric load data and are meant to allow evaluation as to whether a CHP system is feasible. Only after such an analysis proves positive, would an engineer undertake a detailed system design.

Three software tools, namely Building Energy Analyzer (BEA) (2004), Ready Reckoner (2006), and CogenPro (2004), have been evaluated in terms of their input requirements

and their capabilities (Downes 2002). He concludes that Ready Reckoner which analyzes the replacement of a boiler and chiller with a new boiler and an absorption chiller requires a lot of input data pertinent to the existing boiler. On the other hand, Cogen-Pro, which is also meant for the same purpose, requires very little building parameter information, but is conservative in estimating recoverable savings. Finally, BEA requires a lot of information about the building since a detailed simulation is performed. This tool cannot be viewed as a screening tool since it performs hourly simulations.

Another convenient to use automated spreadsheet program is RETScreen (2006) which can analyze CHP and district energy systems. It requires monthly values of heating, cooling, and power loads and equipment description in order to perform the simulations. It has the capability of adding different CHP equipment (either from an existing database or new ones) and computes life-cycle costs and greenhouse gas emission reductions as well. It has been validated by independent consultants and compared with other models as well.

Orlando (1996) provides two detailed case study examples involving the design of CHP systems for a hotel and for an industrial plant using load duration curves. Williams et al. (1998) describe an approach to sizing cogeneration plants which is knowledge based. This decision support is meant to reduce the time and money needed for sizing, and is so structured that the design can be progressively improved depending on how much information is available to identify the optimal size. An example illustrates this approach.

Hourly Energy Simulation Tools for Design

Computer programs which fall in this category require hourly thermal and electric load data and allow detailed system and equipment sizing.

COGENMASTER (Limaye and Balakrishnan 1989) compares CHP alternatives to a base case system where electricity is purchased from the utility and the thermal energy is produced on site. Different financing strategies can also be considered. The software can be operated under different types of input specifications: (a) with a constant average load specified for each hour of the year, (b) hourly data for three typical days of the year, and (c) hourly data for three typical days of each month.

CHP Capacity Optimizer (Hudson 2005) is an automated stand-alone spreadsheet program which computes the optimal capacities of prime movers and chillers that will maximize life cycle, net present value savings from the CHP system. It is based on a methodology involving nonlinear optimization and hourly operation simulation of the CHP prime movers and absorption chillers. The original intent of this tool was to help equipment manufacturers in identifying sizes of CHP equipment most suited to meet current requirements.

The Building Energy Analyzer (BEA 2004) was developed by the Gas Technology Institute in 2002 and upgraded to BEA Pro in 2004. This screening software tool is meant to simplify energy audits in commercial buildings and evaluate the technical and economic potential of CHP systems in such buildings. Several modifiable templates of commercial buildings are built in. It can be used to evaluate several on-site power technologies and cooling options (such as absorption cooling and desiccant dehumidification). It performs hourly calculations over each hour of the year and also includes data from numerous locations and utility rates.

BCHP Screening Tool (Fischer and Glazer 2002) is also a comprehensive detailed hourly simulation program. It is an add-on to DOE 2.1 in that the detailed hourly building

loads computed are used to simulate the performance of a CHP plant and compute associated economics. Several databases are in-built: Typical Meteorological Year (TMY) data for 239 cities in the United States, commercial gas and electric rates for 160 U.S. cities, performance and cost for HVAC equipment, performance and cost for power generating equipment, and building design parameters. Various types of reports and outputs in the form of tables and graphs allow easy interpretation and comparison of results. Users can construct a base case and up to 25 alternative scenario for comparison.

Homer (2005) is a computer program developed by the National Renewable Energy Laboratory (LBNL), meant to evaluate alternative off-grid and grid-connected system options (such as wind, hydro, PV, traditional prime movers, batteries, and hydrogen) for a variety of applications. It uses hourly simulations to evaluate a large number of technology options as well as a large number of technology costs and energy resource availability options. It allows results to be compared based on economic (net present worth) and technical merits. The program also has in-built routines for sensitivity analysis and optimization.

Emissions Calculation Tools

CHP Emission Calculator (EEA 2004) is a spreadsheet program which estimates the net air pollution (NO_x , SO_x , CO_2 , and mercury) from small CHP systems. On-site emissions from the CHP system, displaced emissions from on-site thermal production (e.g., from a steam boiler) and displaced emissions from offsite electricity generation are all considered. Additional inputs allow the user to estimate power to heat ratios as well as define specific operating and electricity-displaced scenarios. RETScreen (2006) described earlier also has the ability to compute emission savings from installing CHP systems.

CHP Qualification Screening—Existing Facility

The purpose of the “qualification screening” phase is to determine if a CHP system makes technical and economic sense. Qualification screening requires answering specific questions before undertaking the engineering and economic analyses. As indicated previously, this evaluation can be performed quickly (about 30 minutes) and the required information is minimal. In order to assist the user, the U.S. EPA—Combined Heat and Power Partnership developed a Web tool called “Is My Facility a Good Candidate for CHP?” which can be used for this purpose. A set of 12 questions is shown in Table 8-3; if the answer is yes for three or more of these questions, the facility may be a good candidate for CHP. If the site is found to be a good candidate for CHP, a feasibility study Level 1 can be initiated.

Level 1 Feasibility Study—Existing Facility

The purpose of Level 1 feasibility study is to determine the technical applicability and the economic benefits of the CHP for the facility under consideration. Unlike the qualification screening, Level 1 feasibility study requires an experienced engineer or CHP project developer with good understanding of the electrical, thermal, and cooling loads and of equipment operation. The task of this individual will be to gather and analyze the necessary information so that he can advise the owner(s) on whether it is worthwhile from an economic standpoint to pursue the CHP project analysis.

1	Do you pay more than \$ 0.06/kWh on average for electricity (including generation, transmission, and distribution)?
2	Are you concerned about the impact of current or future energy costs on your business?
3	Is your facility located in a deregulated electricity market?
4	Are you concerned about power reliability? Is there a substantial financial impact to your business if the power goes out for 1 hour? For 5 minutes?
5	Does your facility operate for more than 5000 hours/year?
6	Do you have thermal loads throughout the year (including steam, hot water, chilled water, hot air, etc.)?
7	Does your facility have an existing central plant?
8	Do you expect to replace, upgrade or retrofit central plant equipment within the next 3–5 years?
9	Do you anticipate a facility expansion or new construction project within the next 3–5 years?
10	Have you already implemented energy efficiency measures and still have high energy costs?
11	Are you interested in reducing your facility’s impact on the environment?
12	Do you have access to on-site or nearby biomass resources (i.e., landfill gas, farm manure, or food processing waste)?

Source: Survey developed by the U.S. EPA—Combined Heat and Power Partnership.

TABLE 8-3 Is My Facility a Good Candidate for CHP?

Initial Data Gathering

The initiation of Level 1 study starts with data gathering. For this purpose, the U.S. EPA—Combined Heat and Power Partnership developed a simple checklist (Level 1 Feasibility Analysis Data Tool) whose main elements are

- 1. Contact information
- 2. Site information and data
- 3. As-built drawings [building(s), plant, utility infrastructure]
- 4. Electric use data
- 5. Fuel use data
- 6. Thermal loads (heating, cooling, domestic hot water, etc.)
- 7. Existing equipment data
- 8. Other data

These data can be obtained by combination of effective communication with the site personnel and a site visit, which is recommended.

Subsequent Analysis

After collecting the data, the engineer will proceed with the following tasks.

Step 1—Identification of Barriers

The intent of this first step is to identify any major uncontrollable obstacle that will prevent the project from being implemented. Typical examples of barriers are existing long-term corporate power purchase contracts that will not allow installation of on-site power generation; local utility and regulatory policies that add CHP constraints and costs; dense and vertical building environment like New York City; special requirements for the stack to exhaust the products of combustion; space for prime mover and auxiliary equipment; noise levels constraints; etc. All these factors have to be considered at this stage; even if one of these obstacles is present, the developer must find a way around any barrier before the project can proceed. The cost of overcoming these obstacles should be included in the implementation budget.

Step 2—Conceptual Engineering

This stage refers to sizing and identifying prime mover technology along with thermally operated equipment such as absorption chillers for waste heat utilization. Conceptual engineering will be based on the site load requirements (peak and usage profile) for

1. Electrical energy
2. Thermal energy
3. Cooling requirements

This information can be obtained from utility bills, submetering (electrical, steam/hot water, chilled water) or in some cases, from trend data. Another approach for obtaining the building load profiles is by *calibrated simulation*. This is the use of hour-by-hour building energy simulation (such as DOE 2.1 E and eQuest) to “tune” or calibrate various physical inputs to the program so that the observed (or actual) energy use (from utility bills or other sources) matches closely with that predicted by the building energy simulation. The accuracy of the calibrated simulation depends heavily on the data available from the site personnel. The results of the calibrated simulation are set of 8760 hourly values for electrical demand, thermal energy for space heating, domestic hot water, and cooling energy. This information along with proper tools can be used for optimal sizing of the prime mover and thermally operated chiller with analytical tools such as ORNL CHP Capacity Optimizer. In cases where the energy simulation program equipped with models for CHP equipment, the analyst can apply the building simulation program to fine tune the results obtained from preliminary results obtained from the ORNL CHP Capacity Optimizer.

In cases where the site has already implemented (or plans to implement) energy conservation measures (ECM), it is important to take into account these measures in the optimal sizing of the prime mover(s) and, if applicable, to absorption chiller. In addition to equipment sizing, the engineer or the CHP project developer will investigate the proper prime mover technology (reciprocating engines, gas turbine, microturbine, etc.). Although a tool such as the ORNL CHP Capacity Optimizer has the capability to size the prime mover optimally, it is suggested that several alternatives (sizes, prime mover technology, absorption chillers) be also investigated.

There may be instances when the engineer is unable to use the optimal sizing tool. In such cases, he/she should consider, as a starting point, a prime mover(s) with the capability of providing a portion of the site electrical power demand and the majority of the site thermal load. This approach is known as *thermal base-loading* following and results in higher system efficiency since it maximizes the use of waste heat. The following is a summary of different types of CHP design options [per Turner (2006) with modifications]:

1. *Sized for isolated operation* where the site is stand-alone, that is, the site does not have grid power, and hence, all the thermal and electric needs have to be met by the CHP system. Excess standby capacity for scheduled and unscheduled maintenance as well as momentary demand spikes and energy creep issues must also be considered.
2. *Sized by electric base-load* where the CHP is sized such that it meets the minimum electric billing demand (which can be gleaned from historic utility bills). Supplemental power is purchased from the electric grid, while any thermal energy shortfalls have to be met by a separate heating source.
3. *Sized by thermal base-load* where the CHP is sized so that most of the thermal energy is met with heat recovered from the prime mover, with any excess electric power sold to the electric grid and any shortfalls met by supplemental grid power.
4. *Sized for intermediate loads* where some amount of thermal load and some amount of electric load are met by the CHP plant. This is probably the most common design option since in actual reality, the final CHP design and equipment sizing will depend on location-specific economics and issues such as energy security and reliability. Economic issues would involve considering not only the cost of thermal and electric energies, but also operation and maintenance costs of the equipment as well as environmental costs.
5. *Sized for peaking loads* where the CHP system is specifically designed to curtail electric demand by utility peak shaving, and thereby save on demand charges.

Economic Analysis

Since the intent of the Level 1 feasibility study is also to determine the economic feasibility of a CHP system, the economic analysis plays a major role in this stage. Typical techniques for economic analysis are *simple payback* which is the simplest (and the least accurate) to more accurate and sophisticated methods such as *present value* (also known as *present worth*), *internal rate of return* (IRR), and *life-cycle costs* (LCC). Chapter 9 discusses these techniques in more detail.

Typically, for Level 1 feasibility study the simple payback method is often adequate. This is simply the ratio of the initial cost divided by the annual net savings. The cost of borrowing money, inflation, and other factors associated with the operation of the system during its lifetime are ignored. However, the simple payback analysis does include the following effects:

1. Heat and power produced by the CHP system, and the estimated amount of each to be used on the site
2. Avoided costs of utility-purchased heat and power

3. Cost of fuel associated with running the CHP system
4. Cost estimates to install and maintain the system
5. Available incentives for CHP installations

These variables are applied to each of the proposed alternatives. It should be noted that, often, estimated equipment pricing is quite accurate at this initial stage, but other project development costs (such as the cost of CHP system tie-in and site construction expenditures, additional structural work, and noise, pollution) are preliminary. Given these uncertainties it is important that reasonable estimate for all other turnkey costs associated with CHP system implementation, operation, and maintenance be included in this preliminary budget. Sometimes additional analysis will be required to account for benefits such as backup power in events of utility outage or potential increase in the utility rates.

The determination to proceed to a Level 2 feasibility study will be based on the simple payback estimated, since owners, based on their own economic criterion, have an upper threshold value. If all of the previously mentioned costs and benefits are included in the preliminary economic analysis, it should provide a fairly accurate representation of the opportunity or benefit of the CHP project.

It should be clear, however, that the results of this economic analysis are simply a necessary phase before proceeding to the more accurate economic study that is part of the Level 2 feasibility study.

Level 1 Feasibility Study—Typical Outline

Although different organizations have their own style and format for a Level 1 feasibility study, it is typical that the associated report comprise of the following sections:

1. Executive summary
2. Preliminary analysis and assessment
 - (a) Facility description
 - (b) Baseline utility cost
 - (c) Facility electrical, thermal, and cooling load profiles
 - (d) CHP systems design options and alternatives
 - (e) Engineering and energy analysis of CHP design alternatives
 - (f) Emissions
 - (g) Utility interconnection
 - (h) Power reliability
 - (i) Budgetary installation and maintenance costs
3. Economic analysis
4. Conclusions and recommendations for Level 2 feasibility study
5. Appendix

Examples for Level 1 feasibility studies can be found at the U.S. EPA—Combined Heat and Power Partnership Web sites.*

*http://www.epa.gov/chp/documents/sample_fa_ethanol.pdf
http://www.epa.gov/chp/documents/sample_fa_industrial.pdf

Level 2 Feasibility Study—Existing Facility

Once a Level 1 feasibility study has been found to be economically and technically feasible, the Level 2 feasibility study is initiated. Many of the preliminary assumptions used in the Level 1 feasibility study will be replaced with more accurate data. Additional data such as operational goals, controls, monitoring, and off-grid capabilities will also be incorporated in this study, so as to revise and optimize the preliminary sizing presented in the Level 1 feasibility study. The results of Level 2 feasibility study should include all the information needed to make a decision on whether to proceed with the project, and typically includes

1. More accurate estimated construction, operation, and maintenance pricing
2. Estimates of the final project economics with a simple payback schedule and a life-cycle cost analysis of the total investment

The economic analysis will be based on final system sizing and proposed operation and will be based on more accurate thermal and electrical load profiles. Accurate data in this regard is measured data obtained from trending (utilizing the existing control system or installing new instrumentation) or from electric utility interval data. Planned site expansion or new construction has to be considered and coordinated with various entities in this facility; for example, engineering, planning, and construction. In cases where the CHP is part of a new construction, substantial cost savings can be achieved, and these avoided costs have to be incorporated in the total implementation cost resulting in improved return on investment of the system.

Several site visits and a comprehensive review of the existing conditions will be required as part of this study, thereby allowing the decision maker to make a well-supported decision.

Typically a *Level 2 feasibility analysis* report should include the following:

- Site load profiles
- System operational schedule
- Mechanical and electrical system components
- Heat recovery
- Systems efficiency
- Sound levels
- System vibration
- Space considerations
- System availability during utility outage
- Utility interconnection
- Emissions and permitting
- Capital cost
- Fuel costs
- Maintenance costs
- Availability of incentives

- Economic analysis including life-cycle analysis
- Financing options
- Preliminary project schedule
- Supporting documents for project execution (proposals, costs, design documents, etc.)

Level 2 Feasibility Study—Typical Outline

As indicated in Level 1 feasibility study requirements for a typical outline of the feasibility study report, each organization has its own style and format for studies. For a typical Level 2 feasibility study the report should include the following sections: (Based US EPA—Combined Heat and Power Partnership Web site http://www.epa.gov/chp/documents/level_2_studies_september9.pdf):

- Executive summary
- Description of existing site plan and equipment
- Site energy requirement
- CHP equipment selection
- Description of preferred CHP system
- System operation
- Regulatory and permitting requirements overview
- Total CHP systems costs
- Assumptions for cash flow analysis
- Discounted cash flow analysis for preferred system
- Appendices

CHP Feasibility for New Facilities

A CHP system for new installations can be considered during the early stages of the design (conceptual design phase). As explained previously, the same qualification test presented in the section “CHP Qualification Screening—Existing Facility” can be applied for new facilities as well. If a CHP system is found to be favorable, the designer can propose a CHP system as part of the development of the design alternatives. With the increased utilization of building energy simulation programs, a preliminary model of the facility can be developed to assist the designer in analyzing various design alternatives, where a CHP system can be one of the alternatives or one of several design alternatives (involving different CHP system sizes). Since optimal CHP prime mover sizing is more complex than other mechanical and electrical equipment in buildings, combining the strength of the building energy simulation program and other tools for optimal selection of CHP prime mover and absorption chiller (e.g., the ORNL CHP Capacity Optimizer) can be very beneficial.

The following is a brief description of a procedure that can be applied for evaluating a CHP system in the conceptual stage of the design. This procedure is based on utilizing

the DOE 2.E hour-by-hour building energy simulation program along with ORNL CHP Capacity Optimizer:

1. Development of a building energy model using a forward building energy simulation program based on the preliminary design documents (architecture, structural, lighting, plumbing, process, site design criteria, etc.). For equipment such as chillers, boilers and other plant equipment, automatic sizing and typical energy efficiency data consistent with local or required energy standards can be utilized. (Take into account real-time site-specific data and energy costs for improved predictability.)
2. Retrieve from the output of the energy simulation program, hourly reports for 8760 values for the site electrical requirements (excluding any cooling electrical energy), thermal energy (space heating, domestic hot water, process heat) and cooling requirements.
3. Input the hourly data in the ORNL CHP Capacity Optimizer along with the utility rates and typical electrical efficiency and applicability of waste heat for the prime mover and the other mechanical equipment. Run the first iterative simulation to determine prime mover size.
4. Identify a vendor who offers a suitable prime mover, and rerun the ORNL CHP Capacity Optimizer using published data available from technical data sheets of the prime mover inputs for electrical efficiency and available waste heat. The results can be used as a starting point (to size the prime mover) in the building energy simulation (since the building energy simulation does not calculate the prime mover size automatically).
5. Return to the building energy simulation and proceed with the conceptual design.

Chapter 21 provides a case study entitled “Optimal Sizing of Prime Mover and Absorption Chiller Using Hour-by-Hour Building Simulation Program—New School Facility” demonstrates the procedure of utilizing hourly load data and optimal sizing of the prime mover and the absorption chiller.

Although this section discusses new facilities, a similar approach can be used for existing buildings; in this case, the hourly data that will be inputted to the ORNL CHP Capacity Optimizer will be generated by an hour by hour calibrated energy model of the existing building.

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CHP Economic Analysis

Kyle Landis

Itzhak Maor

CHP Economic Analysis

CHP economic analysis is the process by which the economic factors surrounding a proposed CHP plant are analyzed to determine if the project makes economic sense and that the project is a good investment for the stakeholders' funds. The criteria for defining a project as economically viable will vary from project to project, but at a minimum the project typically needs to save money over the "business-as-usual" (BAU) case. More stringent criteria may require the project to perform at least as well as a competing investment. Economic analyses methods vary from a simple payback analysis to the more complicated and detailed life-cycle-cost (LCC) analysis discussed in detail in this chapter.

Simple Payback Analysis

Simple payback analysis is an economic analysis method that looks at the time required to recoup the first costs based on the annual savings realized from the installation of the project. Simple payback analysis does not account for the time value of money, escalation, etc. as does LCC analysis. For CHP projects, which are not typically low-cost projects, use of simple payback analysis is typically limited to the initial feasibility stages of the project. As more detailed study of the project is performed, LCC is usually required. The formula for simple payback is as follows:

$$\text{Simple payback (years)} = \text{project first cost} / \text{annual savings}$$

where project first cost = the total installed cost of the project as defined in the section "Estimating Budgetary Construction Costs" and annual savings = the sum of the savings in energy, operations, and maintenance costs compared to the BAU case.

Life-Cycle-Cost Analysis

LCC analysis is a process by which the available economic factors spanning the life of a system are considered in terms of the time value of money and to the degree appropriate

for the required level of accuracy when undertaken. By developing the LCC of each alternative under consideration (including the conventional or BAU case), one can determine the comparative advantage of the proposed system in terms of receiving the best economic return on the money invested (also called rate of return or internal rate of return). The following sections of this chapter explain in detail the components of an LCC analysis, and describe the process of performing an LCC analysis, including examples.

The following sections define the economic terms for components of an LCC analysis, as well as explain how to estimate energy use and cost, estimate annual maintenance costs, estimate budget construction costs, and calculate life-cycle costs.

Alternatives

Alternatives are simply all of the options that are to be considered as part of the analysis. Typical alternatives for a combined heat and power (CHP) LCC consist of the BAU case (buying power from the local utility and fuel for thermal requirements) and multiple alternative cases using different types and sizes of equipment.

The BAU case is the minimum that can be done to still satisfactorily meet the thermal and electric demands of the system. An example of a BAU case might be either using existing or installing new boilers and chillers to meet the facility thermal loads and purchasing electricity from the local utility to meet the electric loads of the facility. If existing equipment is planned to be used in the BAU case, consideration must be given to the age and condition of the equipment. If the equipment being used in the BAU case has a remaining useful service life less than that of the alternatives to which it is being compared, then replacement of the existing equipment must be factored into the LCC of the BAU case. Similarly, if the existing equipment will need major overhauls (outside of that to be considered in the annual maintenance costs), then those costs need to be factored into the LCC of the BAU case as well.

The alternatives to which the BAU case is to be compared can be as few or as many as is desired. A keen understanding of CHP systems will help to eliminate alternatives that are not economically feasible prior to determining the LCC of the alternative. For example, if the project being considered has a relatively large electric load and a relatively small thermal load, then alternatives that provide considerably more thermal output than electric output should have already been eliminated from consideration during the conceptual engineering phase as the thermal load will be “dumped” on a regular basis as electric demand is met. Refer to Chap. 8 for additional information.

Engineering Economics

The concept of engineering economics can be summarized as the process to determine the best economic decision (e.g., the highest rate of return or the lowest LCC) given a number of alternatives which require technical knowledge and expertise in order to assess. While the economic concepts used are not unique to engineering economics, the ability to determine the “input” to economic formulas and criteria is unique to engineering economics. For example, assume one is focused solely on the economic aspect of a design decision and wants to estimate the annual cost savings, if any, from employing a CHP alternative in lieu of purchasing needed natural gas and electricity from local distributing public utilities. Accordingly engineering economics must be applied to calculate the technical components of the costs savings, such as energy use and cost and operation and maintenance requirements, for example.

Life-Cycle-Cost Process

The typical life-cycle-cost (LCC) process involves estimating the annual costs (cash flow) that result from each of the alternatives under consideration, counting for factors such as escalation (inflation) and the cost of financing, and comparing the resultant net present values (NPV), which is discussed later in the chapter. The alternative with the lowest NPV will be the best alternative in economic terms (best investment of capital). If long-term cost savings, as represented by a positive NPV of annual savings, is obtained with a fixed interest rate and realistic selection of economic factors, including escalation, that the alternative is considered to be economically viable.

Capital Costs versus Annual Costs

Capital costs are those associated with constructing the CHP system including: plant building(s), the purchase and installation of all necessary equipment, controls, instrumentation, piping, and appurtenances needed for operation. Typically, capital costs are the first costs of an alternative. Capital costs can occur further into the project replacing existing equipment that is at the end of its service life or replacing equipment with a service life less than that of the entire project. The determinant of how these costs are considered will be whether money for less than annual replacement of equipment is budgeted annually and saved for the year when the replacement occurs, or if capital is obtained at the time of the replacement.

Annual costs are those that are regularly occurring, typically on an annual basis. Examples of annual costs are fuel purchases, electricity purchases from the utility, labor costs for operators, cost of consumables, and periodic maintenance and repair costs. As mentioned above, some maintenance items, repairs, or replacements happen at a frequency of more than 1 year. In this case, the annual cost calculation may “annualize” those costs. For example, if the project life is 20 years, but every 5 years, the engine needs to be rebuilt, one-fifth of the rebuild cost is budgeted and set aside every year.

Cash Flow Diagram

Cash flow (also called net cash flow) is defined as the total receipts and payments made in a given time period. Table 9-1 shows anticipated cash flows following construction and beneficial use. The receipts column shows a higher cash position in a given time period, whereas the payments column indicates a lower cash position in a given period. It is possible that in a given period, there were multiple payments and receipts, but the cash flow table represents the sum of all of these individual transactions as one number.

Time Period	Receipts (\$)	Payments (\$)
Year 0	0	2,000,000
Year 1	500,000	0
Year 2	500,000	0
Year 3	500,000	0
Year 4	500,000	0
Year 5	500,000	0

TABLE 9-1 Sample Cash Flow

A cash flow diagram represents a cash flow table in a diagrammatic manner using a horizontal line to represent the time periods, upward facing arrows for receipts (positive cash flows), and downward facing arrows for payments (negative cash flows).

Time Value of Money

The premise of “time value of money” is that, due to escalation (inflation) and potential interest earnings, the same money received in the future is worth less than that same money received now. That is, \$1000 today is worth more than \$1000 in 10 years. Therefore, an investment that will save \$1000 in the initial year is worth more than the same investment resulting in saving \$1000 ten years later. If an 8 percent return on investment (the discount factor) is available for 10 years, then \$1000 in 10 years is worth \$463 in today’s dollars (or has a present value of \$463). Conversely, if that same \$463 was invested at 8 percent for 10 years the final value will be \$1000.

Discount Rate

The discount factor is one of the most important numbers used in life-cycle-cost analysis. The number used in the discount factor equates future values with present values. That is, the discount factor is the number used to determine the equivalent present dollar value given some future dollar value. In general, the discount factor should equal the long-term cost of money. Higher discount factors will “discount” future values even more. That is, a greater discount factor will reduce the importance of future costs (or savings) on the economic analysis.

Interest Rate

Interest rate is the rate paid by a borrower for the use of someone else’s money, or the return a lender receives for deferring the use of their money to lend it to a borrower. If the capital to construct a project is borrowed, the interest rate will be paid to the lender. If the money is diverted from other possible investments or uses, then the interest rate is the rate of return that could have otherwise been received for investing that money (e.g., spending the capital to construct the plant versus purchasing a savings bond with a return on investment of 3 percent).

Equivalence

Equivalence is the concept that allows for the economic comparison of different alternatives by equating dissimilar factors such that the alternatives are compared on a “like-for-like” basis, such as net present value or equivalent uniform annual cost. Economic equivalence occurs when two cash flows (or two alternatives) have the same net effect or monetary value, and therefore, the choice of either one would produce the same economic outcome. The concept of equivalence can be used in engineering economics to determine the “break even point” of a particular factor of the analysis. Economic equivalence is therefore considered independent of the point of view, that is, it should not matter whether you are looking from the point of view of the lender or the borrower.

Two basic assumptions are made when applying the equivalence concept to economic analysis. First, it is assumed that any money not invested in the proposed project would otherwise be invested at the prevailing interest rates. Secondly, the prevailing interest rate for all alternatives considered is assumed to be the same.

In order to be able to calculate equivalence, a common time basis is required. The overall duration of the analysis must be the same, such as a 20-year analysis. However, different alternatives could have cash flows that are based on time periods. For example, Alternative A may consider the interest earned on the money not spent on a monthly basis, whereas Alternative B may consider the cost savings of the installed project on an annual basis. In engineering economics, this is typically accomplished by calculating the present worth of the cash flow, which is discussed further in the following section.

Another aspect of economic equivalence is equating the interest rate over the multiple time periods analyzed. If the interest rate were to change at a time period of the analysis, then economic equivalence would change and have to be recalculated.

Utilizing the above described concepts of economic equivalence, any variable of a project can be analyzed to assess the point of equivalence, or breakeven point. For example, the fuel price escalation rate at which the two alternatives have the same economic effect can be calculated. It can be further determined that at a fuel price escalation rate above that found to provide equivalence, that one alternative is favored over the other, and vice versa. For example, at annual fuel escalation rates of less than X percent, the proposed project may be found to result in annual cost savings over its anticipated service life and is therefore economically viable; however, at annual fuel escalation rates greater than X percent, that same project may be found to cost more than the BAU case, and therefore not be economically viable. At a fuel escalation rate of X percent, the BAU case and the proposed project would have the same economic outcome.

The concept of equivalence can be applied to any of the factors of the analysis, such as discount factors, escalation rates, capital costs, and maintenance costs. Evaluation of multiple cases of these factors is called a sensitivity analysis, and is used to determine how sensitive the economic equivalence of the project is to actual input factors.

Present Worth

Present worth (also called present value) is the current value of a future series of annual payments. The future payments that make up a cash flow are discounted to reflect the time value of money. Present worth can be calculated to determine the effect of interest paid, the discount rate applied, or inflation. The mathematical definition of present worth is

$$C_t = C / (1 + i)^t$$

where C_t = present value of C monetary units t time periods in the future (present value or PV)

i = discount or inflation rate

t = number of time periods

Table 9-2 represents the present worth of a simple series of future payments discounted at a rate of 5 percent. As shown the present value of the future payments is less (discounted) each year.

Net Present Value

The net present value of a series of cash flows is simply the sum of the present worth of each of the anticipated cash flows:

$$NPV = (C_1 + C_2 + C_3 + C_4 + \dots + C_n)$$

Time Period	Payments (\$)	Present Worth (\$)
End of year 1	10,000	9,523.81
End of year 2	10,000	9,070.29
End of year 3	10,000	8,638.38
End of year 4	10,000	8,277.02
End of year 5	10,000	7,835.26
Total	50,000	43,344.76

TABLE 9-2 Present Worth Example (at 5 Percent Discount Rate)

In example, present in Table 9-2, the net present value would be expressed as

$$\text{NPV} = (\$9,523.81 + \$9,070.29 + \$8,638.38 + \$8,277.02 + \$7,835.26) = \$43,294.77$$

So while the sum of the cash flow is \$50,000, the NPV is \$43,345, and given a 5 percent rate of return, \$43,345 today is equivalent to receiving \$10,000 per year for the next 5 years.

Escalation Rates

Escalation rates are that rates at which the costs of goods or services increase. Escalation rates that are typically considered in an LCC analysis are those of energy (purchased electricity and fuel), labor (operations and maintenance labor, as well as administrative labor costs), permitting costs, and parts and general goods costs. Escalation rates vary from country to country, by region, by industry, by labor source, and most importantly over time. The appropriate escalation rates this year may be much different from a decade ago or from 10 years from now.

Length of Analysis

The length of the LCC analysis is an important consideration. A typical analysis length is approximately 20 years, though it will vary from project to project. Different portions of the project investment will have different useful service lives, and therefore the useful service life of the assembled project is difficult to estimate and use as a basis for the length of analysis. For example, the plant building may have a 50-year life, the prime mover a 20-year life, and the piping a 30-year life. The further into the future the analysis looks, the harder it is to predict analysis variables such as interest rates, discount rates, and escalation rates and the confidence level in the analysis is therefore weakened. Project investors may also have a standard analysis length that is used for all analyses, or a specified time period in which they need to realize savings.

Salvage Value

Salvage value is the value of the equipment, building, etc. at the end of its useful service life. Whether or not salvage value is considered is primarily dependent on the length of the analysis, as discussed in the above paragraph. The salvage value of any equipment that reaches the end of its useful service life and is replaced during the analysis period should be considered in the cash flow of the economic analysis. The actual effective amount of the salvage value and its significance to the overall analysis is affected by many factors, such as whether the equipment was fully depreciated at the point that it

is taken out of service; market value of the equipment (either resale or scrap), which in turn can be affected strongly by the advance of related technologies new (stricter) regulations; and the cost of demolition/removal of the item.

Equivalent Uniform Annualized Cost

Equivalent uniform annualized cost (EUAC) is an annual amount that is equivalent to the sum of all of the cash flows of an alternative. EUAC can be useful metric in comparing alternatives with different project cash flows.

Calculating Estimated Energy Use and Cost

The largest portion of the annual costs in the LCC analysis of a CHP plant (or the base case) is the energy costs. The energy usage is determined from computer modeling. Energy use is in the form of electricity or natural gas consumption. The electricity and natural gas pricing or rate schedules may be complicated with respect to time of year, location, type of use, on-peak, mid-peak, or off-peak periods. Electricity rates are normally expressed in dollars per kilowatthour (\$/kWh), while price of natural gas is usually expressed in terms of dollars per therm or dollars per million Btu (\$/therm or \$/MMBtu). Electricity rate schedules also include demand charge, which is an additional charge separate from the rate charge. Demand charge depends on the maximum power usage during on-peak period, also referred to as demand period. The purpose of demand charge is due to the cost of providing utility and distribution capacity to meet a facility's peak electrical requirement. Demand may be "ratcheted" back to a period of greater use in order to provide the utility with revenues to maintain the production capabilities to fulfill the greater-use requirement.

Utility-supplying companies use different methods to tailor their rates specific to the needs of their consumers. The charge rate structure for gas and electricity cost for a facility or plant is location-specific. Some of the different electrical rate structures used are as follows (Maor 2008):

- *Seasonal pricing.* Utility charges usually vary by season for most utilities. These variations may be indicated in their rate schedules through different demand and energy charges in the winter and summer.
- *Block pricing.* Energy and demand charge may be structured in one of three ways or combination of
 - An inverted block pricing structure where the rate increases with increase in consumption
 - A declining block pricing method where the rate decreases with increase in consumption
 - A flat structure where the rate does not change with consumption

Most utility companies offer rates with more than one block pricing structure. A utility provider may offer some combination of inverted, declining and flat block rates, often reflecting seasonal energy cost differentials as well as use differentials.

- *Time of use rates (TOU).* TOU is used for pricing of electricity only. The purpose of the TOU is to inform the consumer regarding the cost of energy during off-peak,

mid-peak, and on-peak periods. Proper TOU price information allows consumers to defer energy use until costs are lower. TOU rates are fixed in advance usually at the time of signing the contract, and are not subject to change during the contracted period.

- *Real-time pricing (RTP).* RTP allows rate changes on an instantaneous basis. Real-time pricing requires both a meter that reads electricity consumption on a periodic basis (such as hourly), and a pricing structure which correlates that wholesale electricity cost during the time period in which the meter is read. RTP allows utility providers to charge more during on-peak periods, the times of the day when their demand and cost to generate is greatest—and less during off-peak periods when their demand and costs to generate is lower. RTP provides consumers an incentive to minimize energy demand during on-peak periods. Consumers would gain operating savings by shifting consumption from time periods with high wholesale prices to time periods with low wholesale price.

While energy costs will vary for different locations and utility providers, typical costs may include some or all of the following:

- *Electric energy costs.* Portions of this cost may include the generation costs, distribution costs, taxes and fees, and are billed on a cost per kilowatt basis.
- *Electric power costs (demand charges).* Portions of this cost may include generation costs, distribution costs, taxes, and fees, and are billed on a cost per kilowatt basis, usually for the highest demand in a billing period.
- *Standby charges.* Some electrical utilities will charge an interconnected facility a standby charge to guarantee electrical power capacity equal to the installed capacity of the CHP plant.
- *Natural gas or fuel oil charges.* Sometimes a special “cogen rate” can be obtained, or direct contracts can be negotiated independent of the local utility as a result the quantity of fuel being purchased over an extended time period.

Fuel costs often vary regularly with the market and many CHP plants will contract a mix of real-time pricing, and short- and long-term (futures) contracts to try to keep fuel costs as low as possible.

As discussed in Chap. 8, in order to estimate the energy costs, one must first estimate the energy usage. The first step in this process is having a clear understanding of the facility energy usage profiles. Depending on the detail level of the analysis, one may look at energy usage anywhere from an annual average to detailed, hour-by-hour usage for the entire year. Energy usage profiles that are considered in analyzing a CHP plant are electric usage, thermal usage (e.g., heating, domestic hot water production), and cooling usage. The interaction of these energy usages determines how the facility will have its energy needs met under the BAU case, as well as under each of the CHP alternatives being considered. Once the energy usage is determined costs can be assigned to each component of energy used (or saved).

Methods of estimating energy usage and costs may be as simple as looking at detailed facility data to developing models using purpose-specific modeling programs or building spreadsheet models. As discussed in Chap. 8 several commercially available software programs are quite adept at estimating energy usage of many types of CHP applications. Advantages to software models are ease of use, repeatability, and presumed

quality assurance of the model. Disadvantages of some software models may include limitations in modeling unique CHP plant applications, the model may have flaws that are less than initially apparent to the user, or require “tricking” the simulation model by adjusting the input to model an aspect of the CHP scenario that the model does not appear to support. Spreadsheet models can be built that allow for very detailed analysis of unique or “out of the ordinary” CHP applications, or allow the modeling to report a unique aspect of the results. Advantages of spreadsheet modeling, for example, Microsoft Excel, include the ability to build as detailed and unique of a model as the user desires, and increased ability to follow the logic behind the calculations. Disadvantages of spreadsheet models include more time to initially create and check the model, a higher chance of errors if close attention is not paid to detail, a lack of annual hour-by-hour calculation, and making even small changes to the model once it is substantially complete can prove challenging.

Estimating Annual Operation and Maintenance Costs

Another important aspect of estimating the annual costs of the BAU case or a CHP plant alternative in an LCC analysis is the annual operation and maintenance costs. These costs include

- Preventative/periodic maintenance of equipment
- Costs of consumables (lubricants, urea, test gas for emissions monitoring, etc.)
- Repair of equipment
- Rebuilding equipment during the life of the analysis
- Cost of permitting and annual testing (i.e., permit to operate, emissions control testing)
- Cost of operators and maintenance personnel
- Cost of administrative staff

Permitting and testing costs can usually be estimated by discussing with the authorities in charge of such permitting or tests, or from companies that provide those testing services. Costs for operations and maintenance staff, as well as maintenance staff, can vary largely from region to region and from facility to facility. Some facilities may already have these staff positions covered, whereas some facilities will have to start from the beginning in staffing their operation. Some CHP alternatives may be designed to operate with minimal operator intervention, whereas other facilities (i.e., those that produce high-pressure steam) may require full-time attended operation.

Most major equipment manufacturers can offer historical maintenance and repair costs. Often time, maintenance contracts are available that provide all necessary maintenance and repairs on either a flat annual rate or based on hours operated or plant output. Additionally, publications are available which offer typical maintenance and repair costs based on surveys of equipment already installed and operating at various facilities. Below is information from an ASHRAE research project regarding prime mover maintenance costs.

Prime Mover Operation and Maintenance Costs

Table 9-3 provides reciprocating engine operations and maintenance (O&M) costs. It should be noted that the fixed cost is approximately 6 percent of the total hourly O&M for this prime mover size range.

Source	Applicable Year	Electric Capacity			
		100 kW	300 kW	800 kW	3000 kW
Schienenbein et al. (2004)—PNNL	2000	0.0145	0.0125	0.0104	0.0090
Energy Nexus Group (2002)—EPA	2001	0.0184	0.0128	0.0097	0.0093
LeMar (2002)—ORNL	1999/2000	0.0120	0.0100	0.0800	0.0075

Source: Maor (2008).

TABLE 9-3 Summary of Natural Gas Reciprocating Engines Combined Fixed and Variable O&M Costs (\$/kWh)

LeMar (2002) provides operation and maintenance costs for engines, microturbine, and fuel cells for the years 1999/2000 in a lump-sum format (fixed and variable combined). The microturbine O&M cost data is organized in a tabular format for microturbine ranging from 45 up to 600 kW. Although the size range seems to be large, the O&M cost ranges from only \$0.01 to \$0.009 per kilowatt. Firestone (2004) based on DER-CAM (Distributed Energy Resources Customer Adoption Model) suggested a range for variable O&M costs for microturbines of 28 to 100 kW. This price is \$0.015 per kilowatt. Additional information for microturbine O&M cost can be found in EPRI report 1007675 (2003). This report is based on data from several microturbine manufacturers for systems ranging from 30 to 100 kW. The stated O&M costs range from \$0.007 to \$0.013 per kilowatt, where the majority are around \$0.011 per kilowatt (Note that the EPRI prices are applicable for the year 2002.) (Maor 2008).

Estimating Budgetary Construction Costs

Estimating the budget construction cost is important at various stages during the planning and design process, and affects the validity of a prior LCC analysis and may require the user to reallocate internal and/or obtain additional funding needed for the construction of the project. Depending on the depth of the LCC analysis being prepared, budget construction cost estimates can range anywhere from a cost per kilowatt basis to a detailed item-by-item cost estimate basis. Resources for preparing the budget construction cost estimate include equipment manufacturer/vendor quotes, cost estimating publications, contractor estimates, and professional costs estimators. It is advisable to always obtain multiple vendor quotes for all major equipment since the significant portion of the project cost for a typical CHP project is in the equipment, and cost estimating publications do not often address such specialized equipment needs.

The key to preparing an accurate budget construction cost estimate is having a keen understanding of how the plant will be constructed. For example, knowing that piping has to be furnished and installed is important, but realizing that hangers, supports, and bracing are required is also important in estimating the correct cost. Going even further, understanding that the installer will be working in a tight space or at high platform levels, then earlier assumed project cost may increase as a result of higher than anticipated installation costs. Where the estimator is able using three-dimensional (3D) software,

for example, BIM to walk through the step-by-step process of constructing each portion of the CHP plant that is to be constructed, then the accuracy of the estimate is more likely to improve; however, this information is not typically available during the planning stage.

Other important components of the budget construction cost estimate to consider in addition to the “nuts and bolts” material and labor costs are

- *Subcontractor markup.* Oftentimes, cost estimating publications provide the raw material and labor costs. The actual “burdened” costs of labor can be much higher when all of the payroll taxes, benefits, etc. for the worker are considered. Markups of 10 percent for materials and up to 50 percent for labor have been used by the author, and are applied only to costs estimated from cost estimating publications (not to quotes from equipment vendors, for example).
- *Location factors.* Most cost estimating publications provide location factors to adjust for the higher or lower costs of materials and labor in the area where the project is located. In the United States these may be in the range of ± 10 percent, and are added to the subtotal of the costs estimated from the cost estimating publication (with subcontractor markups).
- *Taxes.* Sales tax may be applicable to all purchased material depending on the locale, and is applied to the subtotal including the above markups and location factors.
- *General requirements.* General requirements cover the contractors cost of reproduction, office equipment, constructions trailers, mobilization and demobilization, project management, etc. Typical values are often around 5 percent, and are either estimated individually or the 5 percent factor is applied to the subtotal including the sales tax.
- *Contingency.* A contingency amount should be added to cover unexpected costs. Contingencies may range from 5 percent for a very detailed cost estimate based on final engineering drawings to 25 percent for a rough “order of magnitude” type cost estimate based on concept level ideas. The contingency is applied to the subtotal including the general requirements.
- *Insurance and bonds.* The cost of the contractor’s insurance and bonds is typically around 3 percent, and is applied to the subtotal including the contingency.
- *Contractor’s overhead and profit.* This typically ranges from 10 to 15 percent and is applied to the subtotal including the insurance and bonds.
- *Owner’s project costs.* In addition to the budget construction costs, additional project costs should be considered in the LCC analysis, such as the cost of engineering design, testing, and inspection fees, and the owner’s construction administration. Project costs are typically about 20 percent of the construction costs.

Calculating Life-Cycle Costs

Calculating life-cycle costs brings together the project cost, the annual operating and maintenance costs including energy costs, the cost of obtaining financing, any taxes, the time value of money, and escalation into one value (the net present value) so that alternatives can be compared on a “like for like” basis.

Discount rate	5%
Maintenance escalation rate	3%
Natural gas escalation rate	2%
Electric escalation rate	2%
Administration and permitting cost escalation rate	3%

TABLE 9-4 Sample LCC Calculation Assumed Economic Factors

Tables 9-4 to 9-6 provide a sample LCC calculation. Table 9-4 shows the economic factors assumed, Table 9-5 shows the annual costs, escalated year by year over the project life and equated to the present worth, and Table 9-6 provides a resultant LCC calculation.

In sample calculation (Table 9-6), the total present cost is \$37,850,000, which is the sum of the \$9,000,000 project cost and the \$28,850,000 NPV of the annual costs.

End of Year	Annual Costs					Present Worth (\$)
	Maintenance Cost (\$)	Administration and Permitting Costs (\$)	Fuel Cost (\$)	Purchased Electricity Cost (\$)	Total Annual Costs (\$)	
1	400,000	30,000	1,200,000	300,000	1,930,000	1,840,000
2	412,000	31,000	1,224,000	306,000	1,973,000	1,790,000
3	424,000	32,000	1,248,000	312,000	2,016,000	1,740,000
4	437,000	33,000	1,273,000	318,000	2,061,000	1,700,000
5	450,000	34,000	1,298,000	324,000	2,106,000	1,650,000
6	464,000	35,000	1,324,000	330,000	2,153,000	1,610,000
7	478,000	36,000	1,350,000	337,000	2,201,000	1,560,000
8	492,000	37,000	1,377,000	344,000	2,250,000	1,520,000
9	507,000	38,000	1,405,000	351,000	2,301,000	1,480,000
10	522,000	39,000	1,433,000	358,000	2,352,000	1,440,000
11	538,000	40,000	1,462,000	365,000	2,405,000	1,410,000
12	554,000	41,000	1,491,000	372,000	2,458,000	1,370,000
13	571,000	42,000	1,521,000	379,000	2,513,000	1,330,000
14	588,000	43,000	1,551,000	387,000	2,569,000	1,300,000
15	606,000	44,000	1,582,000	395,000	2,627,000	1,260,000
16	624,000	45,000	1,614,000	403,000	2,686,000	1,230,000
17	643,000	46,000	1,646,000	411,000	2,746,000	1,200,000
18	662,000	47,000	1,679,000	419,000	2,807,000	1,170,000
19	682,000	48,000	1,713,000	427,000	2,870,000	1,140,000
20	702,000	49,000	1,747,000	436,000	2,934,000	1,110,000
Total	10,756,000	790,000	29,138,000	7,274,000	47,958,000	28,850,000

TABLE 9-5 Sample LCC Calculation Annual Costs

Project Cost (\$)	NPV of Annual Costs (\$)	Total Present Cost (\$)
9,000,000	28,850,000	37,850,000

TABLE 9-6 Sample LCC Calculation Results

Note that the sum of the annual costs is nearly \$48 million, but the future value is discounted to the amount shown in Table 9-5. The total present costs of an alternative would then be compared with that of other alternatives to determine the alternative with the lowest LCC.

Determining Appropriate Escalation Rates

Various Federal Energy Management Building LCC (BLCC) Programs can be readily accessed via the Internet at http://www1.eere.energy.gov/femp/information/download_blcc.html#eerc and can be a great resource for determining appropriate energy escalation rates, including free downloadable software that calculates appropriate energy escalation rates individually, and in a table format if needed. Some local public utility commissions also conduct fuel and electricity pricing forecast studies that are available to the public.

Reference

Maor, I., and T. Reddy, 2008. Near Optimal Scheduling Control of Combined Heat and Power Systems for Buildings, *Research Project 1340-RP*, American Society of Heating, Refrigerating and Air-Conditioning Engineers, Atlanta, GA.

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Design

CHAPTER 10

The Engineering Process

CHAPTER 11

Electrical Design Characteristics
and Issues

CHAPTER 12

Obtaining a Construction Permit

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The Engineering Process

Lucas B. Hyman

Kyle Landis

When a well-thought-out thoroughly vetted CHP study shows an attractive rate of return or that CHP has the lowest life-cycle cost, the next step is to begin preparing the construction documents (i.e., plans and specifications). Key decisions are made during the design process, which will affect every aspect of the project from cost to appearance to function to performance. Architects, contractors, and owners, as well as engineers need to understand thoroughly the engineering process, so that each participant contributes their needed part to the design process effectively.

Engineering includes mechanical, electrical, and structural engineering. If a new building is needed, the design effort will also include architecture and civil engineering and possibly landscape architecture. Additionally, most projects will require a code compliance specialist (especially for permitting and air quality applications) and project cost estimators. Large projects also often require value engineering, construction managers, commissioning specialist, and/or other third-party review of the ongoing design.

Even when the basic CHP design concepts are fairly simple, coordinating all of the details as well as the different engineering disciplines can sometimes be complicated and challenging. It is, therefore, very important that the selected engineering team members not only thoroughly understand the design process but also have CHP design experience. This CHP engineering team's design knowledge and experience on successful projects is the key factor, which ensures a successful CHP project.

As discussed in previous chapters and as shown in Fig. 1-3 in Chap. 1, there are a variety of components and systems that need to work together in order to achieve a well-functioning sustainable CHP system. Key decisions regarding CHP type and size and system type and configuration should have been at least conceptually developed during the study phase.

This chapter addresses the selection of the most qualified engineering team, the most cost-effective and efficient engineering design approach, and other key CHP design issues. It also discusses some of the important intangibles that go into developing a successful CHP design package.

Hiring the Best Engineering Team

The best interests of the owner-operator, developer, and/or facility are served when engineering selections are based on hiring the most qualified and experienced team. It is seldom wise to hire based on engineering cost. Such a process may be compared to hiring someone to perform your heart transplant based on a low bid.

Hiring an engineering team with the lowest proposal cost may very well end up costing more during construction and in subsequent operations. A firm with less experience may well underestimate the design effort and then cut corners in an effort to stay on the design budget. The fact is the more experienced firm can do the project for less engineering effort because they have their experience on past projects to help guide them through the project.

Facilities should have a preagreed upon engineering fee based on the size and difficulty of the CHP construction project (often based upon a percent of the construction costs) as a benchmark for whichever engineering team is finally selected. That way, engineering teams selected for interview compete on their respective qualifications, experience and best approach to the CHP design. Such a process allows the owner or developer to select the engineering team best suited for the project.

Selection processes which include engineering cost proposals may be appropriate, where all firms selected for interview are all preapproved and are required to respond to a more detailed owner-operator furnished scope of work, project milestones, and a completion schedule. This is only appropriate when all of the firms considered are first determined to be highly qualified, and equally capable of providing the high-quality CHP project desired.

The selection process hiring the most qualified engineering team often begins with a "request for qualification (RFQ)." The responding engineering teams prepare their "statement of qualifications (SOQ)" carefully to follow the owner's instructions. A good statement of qualification presents information about the firm's history, personnel, experience on this kind of project, cost control history on projects, percentage of change-orders, and a contract person for the projects listed.

The owner reviews the submitted SOQs from all of the engineering firms and develops a "short list" of the top three to five firms that they would like to consider further. The next step is to either interview the firms or request detailed project proposals. In either case, the areas where more information or details are desired should be clearly presented to the selected firms.

Based on the interviews and/or project proposals, the owner's panel must then rank each of the engineering firms generally using a predetermined weighting process. Usually a project proposal is evaluated for its technical proposal and the cost proposal is evaluated separately. After evaluation of all the factors, the owner or developer selects an engineering team to perform the CHP project. The winning engineering team if selected on the basis of its technical proposal and/or interview should be asked to provide an engineering cost proposal. In lieu of accepting a cost proposal, the owner can also elect to negotiate with selected first place engineering firm, and if unable to reach a mutual understanding would be free to contact the second place firm and repeat the same process, if desired.

Request for Qualifications

The owner's RFQ needs to obtain from the engineering team all information needed to create a short list of the engineering firms that owner would like to consider for the

project. The following is a list of some of the items typically requested in an engineering RFQ:

- Business name and address
- Company telephone and fax numbers
- Primary contact information
- Company background and history
- Organization chart
- CHP (or applicable) design experience of the firm (sample projects)
- CHP (or applicable) design experience of the proposed team members
- A description of three similar projects completed in the last 5 to 10 years
- Technical/project approach
- A discussion of project management
- A discussion of the firms' quality assurance/quality control program
- A discussion of the firms' ability to support the owner during the construction process
- The firms' change-order history (lower percent change-orders is usually better)
- Subconsultant information
- Staff availability/work load
- Equal opportunity statements
- Disclosure of any past or pending litigation
- Disclosure of any past or pending bankruptcy
- Key team member resumes
- References
- List of any exceptions to the RFQ

The purpose of the response to a RFQ is to show that the engineering firm has

- The requisite knowledge and experience to develop a good set of plans and specifications required to construct the CHP system
- Specific CHP design experience relevant to the project
- The tools and resources to perform the work
- The man power to get the work done in a timely manner
- Engineers who will work well with the owner's team

The RFQ, which has a given due date, can be advertised to the public or can be mailed to a list of known and/or qualified engineers. As noted, often, the CHP owner-operator will provide with the RFQ the preset rating criteria (points and weighting) by which the engineering firm responses will be judged and firms for interviews would be selected. The rating criteria are typically similar to the RFQ, which may include predetermined points for project experience, points for technical approach, and so on.

The CHP owner-operator or developer should select a panel of stakeholders and interested parties (minimum of three people) including facilities operation and maintenance personnel, facility owners, design and construction personnel, contract administrators, and even outside members including other facility consulting engineers (for peer review) and, or facility owners (someone who has gone through the selection process before). This panel should serve as the selection committee.

Once the responses to the RFQ are obtained by the owner, each member of the owner's panel should review each of the engineering firms SOQ submissions and rank them per the agreed rating system. Sometimes each member individually scores the RFQ and then an average of all scores is used to determine the best SOQ. In other cases, the members who are most familiar with a certain area of the SOQ score that part. Whatever process is used, after all panel members are complete with their review of the engineering firms SOQ submissions, the individual panel members' reviews should be tallied. The responsive engineering firms can then be ranked from highest (best, most responsive) to lowest number of points. The CHP owner-operator can decide on the number of engineering firms to interview and creates what is known in the industry as a short list.

The process of interview or preparation of a detail project proposal is expensive for both the engineering firm and the owner-operator. For that reason, the short list should be limited to the firms the CHP owner-operator or developer is actually interested in hiring. If there are only two firms that are really being considered for the CHP design effort, then just those two firms should be interviewed. If on the other hand there are four firms that could do the work effectively and the owner-operator is not sure who to pick, then it is best to interview those four firms.

The length and format of the interview should be determined in advance. Each team being interviewed may, for example, be given 45 minutes for formal presentation followed by 30 to 45 minutes for questions and answers. The format and length really depends on the size and complexity of the project, as well as by how well the CHP owner-operator has already knows of the engineering firm's reputation and if the owner has worked with the firm on prior CHP projects. Sometimes a shorter presentation with longer questions and answers is warranted, while sometimes the reverse may prove more effective.

The CHP owner-operator should contact each of the invited engineering firms by phone and the information should be followed by a written formal invitation with details on what is expected during the interview. Information should be provided to the firms being interviewed to let them know something about the project as well as the interview process including where and when the interview will take place, and the format for the interview. The CHP owner-operator should also send a letter to the engineering firms which are not selected to be interviewed thanking them for their participation in the selection process. A common practice is to agree to a subsequent "debriefing" phone discussion on firm's perceived strengths and weakness, if requested.

Interviewing

The CHP owner-operator can create a list of questions or concerns prior to the interview for the invited firms to answer during their interview. An alternative is to provide the invited firms with guidelines in advance regarding the topics the owner wants to discuss and how responses will be scored. The owner-operator that only provides

each engineering team the time allotted for their presentation and for questions and answers may learn little except which firm is most skilled at the interview process itself.

If the teams are given CHP owner-operator requirements or selection criteria in advance, the criteria can be used by the engineering team presenters to more effectively structure their presentation and to prepare to answer the owner-operator's questions and/or concerns. This allows a more direct comparison between firms and better assures the owner-operator's project concerns are addressed.

Should no specific project guidelines or selection criteria be offered, often a successful strategy is to try to answer the question "why select XYZ engineering to perform this work" as part of the presentation. One's presentation should try to answer the bullet points outlined on previous pages demonstrating why their engineering firm can offer the greatest value if selected for the work.

During the course of the interview, the engineering firm should look sharp, be well prepared, show their best presentation skills, and demonstrate that they possess the necessary knowledge and relevant CHP project design experience. At the end of the interview, the CHP owner-operators' selection committee should be left with the impression that the interviewed firm has sufficient staffing and financial resources to get the work done in a timely manner on or below budget, will be responsive and easy to work, and if requested can also provide staff for employee hands-on training.

After all of the interviews are complete, the CHP owner-operator selection panel should be provided with office or conference space to meet to discuss openly each of the candidates strengths and weaknesses and be prepared to agree on the engineering firm they believe should be commissioned for the CHP project. The CHP owner-operator should be prepared to promptly notify their first choice as well as each of those participating firms not selected. Once all contract documents and contracts are in place, the project can be awarded and the CHP engineering design process commences usually following a "kick-off" meeting where all the individual firms meet and discuss how they intend to organize their joint efforts and as a basis for information exchange among the parties.

The Engineering Design Process

The engineering design process usually follows a familiar milestone lined path from programming to schematic design, to design development, to the development of construction documents, with owner-operator review and/or peer review, and budget cost estimation occurring prior to signing-off at the completion of each phase of design. Normally, the owner-operator should have already commissioned a well-thought-out project study and developed a project schedule that facilitates the process of beginning design and permitting a CHP system (see Chaps. 12 and 14). It would be foolish to design a new CHP plant only to find out that the local air quality management district or other code authority will not issue a permit to construct, or will add so many unforeseen requirements and costs that the CHP project's expected economic attractiveness are negatively impacted.

The engineering design process involves: developing plant system concepts; selecting equipment; calculating heat transfer requirements; calculating flows and pressure drops; preparing project specifications; and developing plans, elevations, sections, and details so that the CHP plant can be constructed. However, the main CHP concept and

size should have been determined in the feasibility study. The CHP engineering feasibility study, as discussed in Part 2, should provide

- The proposed CHP size, type, and configuration (e.g., two turbocharged 1500-kW natural gas-fired lean burn reciprocating engines operating at full load)
- The type and approximate amount of heat recovery (e.g., 20,000 lb/h of 125-psig steam)
- The emissions requirements (e.g., meet X g of NO_x per horsepower per hour or meet Air Quality Management District Rule 1234)
- A simple block layout drawing showing the approximate location of the proposed CHP plant and equipment
- A simple process flow diagram showing the expected heat balance
- A basic operating strategy/scenario

Developing a Project Management Plan

All successful projects begin with a good work plan, called a *project management plan* (PMP). Good project management is a key to the success of the project and the PMP provides a road map for the CHP design team to follow. The plan allows both the design team and the owner-operator to know what needs to be done and when it is to be done. The PMP helps individual members of the team know what they must provide and when it is required to meet the overall completion schedule.

One of the first key steps is to have a kick-off meeting with all stakeholders: to review project goals and schedules; to discuss procedures, contacts, and access; to gather any available previous studies and reports; and to listen and discuss specific issues and initial fact finding (e.g., known challenges and issues). Meeting minutes should be published to help ensure that every team member has a clear understanding of the issues discussed.

A typical PMP includes a project description, the scope of work, list of deliverables, manpower estimate, project staffing and contacts, and schedule, each of which are discussed and outlined in the paragraphs below. Good project management also involves good open communication between all parties as well as effective quality control procedures.

Project Description

The PMP should begin with a detailed project description so that all parties will have the same understanding of the project goals and objectives. Project constraints, budgets, and schedules should also be identified.

Scope of Work and Manpower Estimate

In the PMP, the project scope of work and manpower estimate identifies the various work tasks, and establishes the time frame, budget, and key milestone dates necessary to meet the CHP project requirements. This part of the PMP identifies key project tasks, organization and staffing requirements, budgets, and project schedule. Often the development of the project plan is done with commercially available management software that is easy to use and which can be modified and quickly shows the impact of any change in requirement or schedule.

Project Orientation and Staffing

A good PMP includes a project organization chart and team directory showing key personnel on the CHP team. The chart illustrates project staff roles and lines of communication. A client team directory should be included along with the kick-off meeting minutes.

Project Schedule

The project schedule should have sufficient detail to ensure that the desired schedule is attainable. The project schedule should include a description of each task, a scheduled start and completion times for each task, the staff to accomplish the work, and the estimated time to perform the task. The schedule should also show the interrelationship between tasks. Milestones are key items which can be used to verify the project is on schedule. These milestones may be highlighted to track major deliverables such as programming, schematic design, design development, and working drawings (construction documents) submittals, as well as the scheduled delivery dates. To be effective, all members of the design team as well as the owner-operator should be kept current on the project management plan and progress toward completion.

Communication

Open, clear communication throughout the entire project is critical. Communication procedures should be established at the kick-off meeting to govern the transfer of information between all project team members. Periodic meetings between the owner and/or his or her project manager, facilities operations and maintenance staff, and the CHP design team will help ensure that the project stays on track, meeting the goals and expectations established at the start of the project.

Quality Control

Quality control is a system or process that helps ensure that standards are followed. In the case of engineering design, quality control includes reviewing drawings, specifications, and calculations for accuracy, proper coordination, completeness, constructability, and to help ensure that ideas are communicated effectively to the construction contractor. Quality control begins on the first day of the project and continues past the final acceptance of the work. The most cost-effective quality control efforts are exerted during milestone reviews. Aside from the daily engineering coordination procedures, the CHP design team should conduct at least two additional quality control checks: a peer review by senior company professionals not directly involved with the project, and a detailed coordination check of the drawings and specifications.

Programming

Programming defines project requirements and is the first critical step of the design process that establishes most of the key criteria. However, ideally as outlined above, most of the key CHP decisions are determined in a well-thought-out feasibility study as discussed in Chap. 8, and the programming phase is a basic verification of the CHP system concept, prime mover selection, proposed heat recovery unit, planned thermal uses, emission requirements, required emission controls, plant equipment controls, electrical interconnection requirements, fuel supply, concept site layout, and expected operating strategies. If a study was not completed, prior to the start of the design effort, then the previous items listed will need to be developed as part of the programming effort. The programming effort should include a review of all applicable as-built drawings

and should include field investigation to establish existing conditions and to confirm location of the proposed CHP facilities. The deliverables (specific products produced by the engineer and delivered to the owner-operator) for the programming phase forms a “basis-of-design” document typically consisting of

- A detailed description of the project
- A basic site plan with property lines
- A basic plant layout showing major equipment
- A schematic system heat flow diagram showing fuel supply, combustion air, flue exhaust, heat recovery, and thermal use
- A basic equipment schedules for major equipment
- A list of applicable codes and standards
- A discussion of maximum allowable emission levels and the proposed emissions reduction equipment
- A proposed drawing list
- A list of proposed specifications
- A concept-level budget construction cost estimate

Planning approval should be obtained from authorities that have jurisdiction over the project prior to conducting the full design effort. The specific authorities having jurisdiction over a project vary from project to project and location to location. Some examples are local building code officials, and regional, federal, and state compliance agencies. These include any required permits and plan checks by various agencies especially the air quality management district (AQMD) which has jurisdiction. Special care must be given to gain project approval from any planning, zoning, or building department which could prevent the CHP plant from being constructed. Sometimes, zoning or building planning department approval requires holding public hearings or special studies with regard to environmental impact, wetlands, historic site surveys, or endangered species. The planning department may impose special studies or project requirements to address concerns or meet ordinances related to sound, emissions, and aesthetics or other issues.

Code/Regulations Review

As part of the programming effort (although sometimes code review is performed as part of the schematic design effort), the architect (if new building facilities are involved) and engineering team should conduct a thorough code and standards review to

1. List all applicable codes that the design and construction must follow (this list is often required by permitting agencies to be included on the construction drawing title pages).
2. Highlight key requirements from those codes and standards that must be considered in the design effort. For example, perhaps the CHP concept requires storing anhydrous ammonia for NO_x emission control, and, therefore, code required setbacks from property lines must be highlighted for incorporation into the proposed plant layout; if these code requirements are not incorporated into the design, costly redesign efforts, or worse, will be required.

Schematic Design and Design Development

During the preliminary or schematic design phase of the engineering design effort, major equipment selections are finalized although subsequent modifications may be needed. Since the number, size, and type of CHP equipment is typically set at this stage of design, any change in the basic assumptions regarding the basis of design is costly and delays the project completion. At this stage, CHP systems are generally represented schematically. A schematic flow and temperature diagram is generally developed for each operating system; though, sometimes more than one system can be combined within a single drawing. A schematic diagram should identify all major equipment including valves, interconnecting pipe, flows, temperatures, and instrumentation. A table should be provided that shows the heat balance. Typical systems for a CHP plant to show in the diagrams include

- Fuel (e.g., natural gas, fuel oil, biodiesel)
- Combustion air
- Engine exhaust
- Emission controls
- Steam, condensate, and feedwater (if using a HRSG—heat recovery steam generator)
- Jacket water (if using an engine generator)
- Hot water
- Chilled water
- Condenser or cooling water
- Fire suppression
- Lube oil

The schematic design includes preparation of basic floor plans, elevations, and sections necessary to understand the scope of work, and the preparation of outline specifications. At this phase, they are sometimes called block diagrams because they show the basic equipment in location and to scale but not all the connections or details. The budget construction cost estimate should be updated.

Design development furthers the design effort established, submitted, and approved in the schematic design stage. Load and energy use calculation are typically required for review at this stage to help ensure that the owner's project requirements are being met and that the assumptions made during earlier stages are still valid.

Specifications

Some owners and general contractors rarely read the specifications, which can be a costly mistake. Every word, every sentence, every paragraph, every section in the specification is important, albeit some more than others. No portion or section of the specification that does not apply should be in the documents. Specifications include general conditions for the project, basic materials and methods of construction and specific pieces of equipment.

As discussed in Chaps. 3 and 4, some of the major CHP equipments include

- Prime movers [e.g., combustion turbine generators, engine-driven generators, microturbines, fuel cells (which is not a prime per se), or other CHP technology]
- Heat recovery units (e.g., HRSG or hot water heat recovery units)
- Thermal-powered chillers (e.g., steam turbine-driven centrifugal chillers or absorption chillers)
- Pumps (e.g., boiler feedwater pumps, jacket water pumps, condensate pumps, chilled water pumps, condenser pumps, or hot water pumps)
- Heat exchangers (e.g., engine jacket water is often isolated from a hot water hydronic system by a water-to-water heat exchanger as it would be costly to supply chemicals, e.g., glycol, for the whole hydronic system)
- Emissions reduction equipment

The basic materials and methods section of the specifications includes material such as concrete, reinforcing bars, piping for each system and use including buried and exposed (e.g., natural gas, steam, condensate, hot water, chilled water, condenser or cooling water, lube oil, vents, drains, and engine exhaust), ductwork (e.g., combustion air intakes and combustion turbine exhaust), HRSG or alternate heat recovery system, as well as pipe supports. Specifications are also required for all electrical work (e.g., conduit and wire, substations, switchgear, motor control centers, switches, and grounding) and for the prime mover and plant control systems, which must be integrated for the effective control and optimization needed to help achieve CHP sustainability. If a new building enclosure is being constructed to house the CHP system, specifications will be required for building components such as doors, windows, roofing, sealants, and paint.

Working Drawings (Construction Documents)

The final working drawing phase encompasses the detailed design effort and is typically divided into 50 percent construction documents (CDs) 95 percent CDs, and 100 percent CDs (plan-check set). The specific percent of completion varies depending on the desires of the owner-operator. Each phase should develop a check set for the owner-operator, estimator and each engineering discipline to review and comment. All comments should be addressed before proceeding to the next phase. Typically, the final plan-check set should be stamped, sealed, and signed by the CHP team design professionals before submittal for permits by the authorities. Any changes from that point on require approval by all code and permit authorities.

The 100 percent CDs should contain all required architectural drawings (if new building facilities or major building renovations are contemplated), civil drawings for building grading and utility connections, structural drawings showing equipment and piping supports (and any new building work), piping system schematics, mechanical drawings for the CHP system itself, and electrical drawings detailing the generator interconnection, protection, and grounding (see Chap. 11). Further, the 100 percent CDs should essentially be complete, coordinated, code compliant, biddable, and constructible. At a minimum, the 100 percent CDs include: a title sheet with project location plan and drawing index; a site plan; schematic flow and instrumentation diagrams; and for each discipline any required demolition plans, installation floor plans, elevations, sections, details, and schedules necessary to show how to construct the proposed CHP system.

Plan Check

Most urban areas in regulated economies require the owner, developer, and/or contractor to obtain permits to construct (see Chap. 12). Failure to obtain a required permit from any agency which has jurisdiction could result in fines or failure to obtain an operating permit after construction. Failure to obtain a permit can also mean possible stoppage of construction with resulting costly delays, and possible forfeiture of investments.

As discussed in Chaps. 6 and 12, multiple permits to construct and to operate are often required with the specific requirements dependent upon the location and the type of facility. As previously noted, typically, planning department approval is required, and should be obtained after programming, as the planning committee will likely want to see some basic site plans and elevations so that they can visualize the proposed work. The air quality permit requires a parallel track effort. As detailed in Chap. 12, the air emission permit process needs to begin early in the design process with any air quality agency concerns addressed and incorporated into the design.

Local building departments or state agencies review construction documents (plans, specifications, and structural calculations) for conformity to applicable code requirements. The CHP team will need to incorporate and respond to all agency review comments and resubmit the construction documents for back-check (or obtain over-the-counter back-check if initial review comments were minor) in order to obtain a permit to construct.

Bid Documents

After all plan check comments have been reviewed and incorporated, the bid documents are printed for agency stamp, as required, after which the owner-operator and, or developer issues the construction documents (i.e., the drawings showing the proposed work, the contract general conditions, and the technical specifications) to contractors for bid (see Chap. 13 for various contractual arrangements).

The owner-operator and/or developer may award the construction contract by a number of methods including using in-house resources, acting as the prime contractor and subcontracting the various trades, by low bid, to a general contractor, or by negotiated bid with a selected contractor. Regardless of the method used, the documents that are used for the final negotiated price are called bid documents. Any changes to the documents (plans, specifications, etc.) after this stage are established by a change to the contract or so-called change-order.

During this bidding or final pricing stage, the CHP design team should answer bidder questions. The questions are formally posed and called requests for information (RFIs). The engineering team should formally reply to the RFIs in a timely fashion and with required addenda to the documents to clarify and to explain any areas of confusion. All RFIs should be funneled through a single responsible party and the CHP team's response should be sent to all prospective bidders. It is important that this be done in a formal way to ensure that no bidder gains an unfair advantage and to ensure that the bids are based on complete and correct information. It should be a policy that any answers which are not so documented are not to be relied on and are not a part of the final contract.

Key CHP Design Issues

The second half of this chapter focuses on highlighting some of the key CHP design issues that should be considered by the CHP engineering team. Combined heat and power systems (CHP) are usually complicated design challenges and as such there are

a number of design issues and challenges that must be addressed and solved as part of the engineering design effort. CHP systems typically include many components that the engineering design team must understand. The engineering design team must have knowledge of the various types, uses, installation requirements, and maintenance requirements for CHP systems. As discussed in Chaps. 3 and 4, some of the major CHP components include prime movers; heat recovery systems; HRSGs; heat exchangers; pumping systems; thermal chillers; steam turbines; applicable, thermally regenerated desiccant air-conditioning systems; emissions control and monitoring systems; cooling towers; radiators; fuel systems (including fuel storage systems); lube oil systems (including oil and waste oil storage systems); steam, condensate, and feedwater systems; hot water systems; chilled water systems; condenser water systems; and building or enclosure heating, ventilating, and air-conditioning (HVAC) equipment.

The engineering team must be able to calculate heat balances, size and select equipment, size piping and ductwork, calculate water, air, and exhaust pressure drops, estimate energy use and cost, as well as develop the proper generator interconnections and electrical protection safeguards.

Of course, as outlined above and discussed in other chapters, the proposed CHP system must meet all the codes, regulations, and standards for the project location. The engineering team will have a good idea of the required codes and standards from previous design efforts and from the code and standards review conducted as described previously. Further, when the actual design effort begins, the maximum emissions levels allowed by the expected permit to operate, the expected raw prime mover emissions levels, and the required emissions reduction equipment must be known, at least conceptually. For example, the air quality agency will require 15 ppm NO_x , the CTG emits 25 ppm NO_x , and the CHP system will employ selective catalytic reduction (SCR) to reduce NO_x to below the allowable maximum emissions limit. Given thorough, well-coordinated, construction documents that follow the required codes and standards, the project should be able to obtain a permit to construct.

As discussed in Chap. 4, the type of prime mover selected to meet the facility's power and thermal needs will have a major impact on the amount, quality (temperature and pressure), and type of heat recovery available, as well as have an impact on the type of systems and materials employed in the CHP design. For example, a combustion turbine generator (CTG) may have a heat recovery steam generator (HRSG) to produce high-pressure steam, while an internal combustion (IC) engine may produce hot water from engine cooling and from exhaust heat recovery. The quality of the recovered heat will, of course, impact the available thermal-powered chiller options, as double-effect absorption chillers and steam turbine-driven chillers require high-pressure steam to operate. Additionally, CTGs typically require high-pressure gas, which usually necessitates the need for gas compressors, while most IC engine generators can use low-pressure gas and often do not need a gas compressor. Generally, the larger the CTG, the higher is the required gas pressure.

Also as discussed in this book, complete use of the available recovered waste heat is paramount to achieving a sustainable CHP system. Therefore, the design must incorporate methods to fully use as much of the recovered heat as possible by providing for a number of thermal uses, such as space heating, space cooling, domestic hot water production, desiccant dryer systems for dehumidification, swimming pool heat, and process loads. Where conditions exist when all of the thermal output cannot be used, a way of rejecting all of the heat is needed (note, full heat rejection capability is typically also required at least for start-up and testing).

Other key issues discussed include CHP plant layout and the need to provide operational flexibility by, if possible, dividing the load across a number of pieces of equipment (e.g., use three smaller pumps instead of one large pump).

The Effects of Prime Mover Selection

As noted above and discussed in this book, the prime mover selection has a dramatic impact on the heat recovery and on the type of systems employed. As discussed in Chap. 4, when compared to internal combustion engines, CTGs typically have higher thermal-electric ratios and thus typically produce much larger amounts of available recovered heat at higher thermal qualities per unit of engine power output. Most CTGs recover all of their heat in a HRSG, which can generate up to about 250-psig steam (the maximum steam pressure is limited by the CTG exhaust temperature which typically is around 1000°F or below, without duct firing, except for recuperated CTGs whose exhaust temperatures are several hundred degrees Fahrenheit lower). Due to the large quantity of excess oxygen in the CTG exhaust, additional high-pressure steam can be produced by burning gas or liquid fuel in duct burners up to a maximum amount of about 30,000 Btu/hp. This option is not available with IC reciprocating engines due to the relatively low amount of excess oxygen.

Engine heat recovery, on the other hand, is usually in the form of low temperature hot water from about 180°F up to a maximum of 250°F, although low-pressure steam—less than 30 psig—can be produced with some engines. With IC reciprocating engines, heat can be recovered from a number of sources including jacket water (JW) for engine cooling, lube oil coolers, turbochargers, and the exhaust gas via an exhaust gas-to-water heat exchanger.

Other differences between CTG and IC reciprocating engine CHP design include vibration isolation requirements, which are typically more challenging with reciprocating engines than with CTGs that use rotating shafts. Also, emissions reduction equipment will be different for different prime movers. For example, fuel cells have very low emissions and may require no exhaust gas treatment, while a rich burn engine may require a three-way catalyst, and a CTG may require SCR.

Heat Recovery Options

With a CTG CHP system that uses a HRSG, which is an unfired boiler, the design engineer should work with a number of HRSG manufacturers to properly layout and specify the proposed HRSG unit(s). Most of the boiler systems and concerns that would apply to any boiler also apply to a HRSG system. For example, a typical HRSG will require: a condensate system and deaerator; feedwater system with feedwater control valve; a properly designed steam outlet pipe and nonreturn valve; flue exhaust ductwork to the outside; pressure and steam drum level control; monitoring, and alarm; safety relief valves and vents; sample ports; and a blow-down system to remove total dissolved solids. In order to properly size the HRSG, which is often custom-designed and custom-built, the engineer will need to specify the following:

- CTG exhaust temperature
- CTG exhaust mass flow rate
- Minimum allowable exhaust stack temperature (the temperature leaving the HRSG)

- Required steam pressure and flow rate
- Condensate return temperature

Of course, the selection must be thermodynamically and economically feasible. Additional consideration should be given to what are the worst-case conditions and minimums required at those conditions. For example, the exhaust gas temperatures can change depending on engine load and inlet-air temperatures. The engineer may want to use the minimum expected exhaust gas temperature for sizing of the HRSG to make sure that peak steam flow rates can be achieved at those conditions. If hotter exhaust temperatures are experienced, the selected HRSG (or heat exchanger) will only perform better. Note that the hottest anticipated exhaust temperature should also be provided to the HRSG manufacturer for proper material selection.

As discussed below, the exhaust ductwork from the CTG exhaust to the HRSG must be carefully designed for minimum pressure drop and should allow for uniform flow and velocity of exhaust gasses across the HRSG (or alternative heat recovery device). The total exhaust system pressure drop needs to be kept as low as possible and below the engine manufacturer's allowable maximum pressure drop. However, as the HRSG (or any heat exchanger) increases in size to achieve a lower pressure drop, the capital cost requirements increase. Likewise, as discussed, as much of the heat must be extracted as possible to achieve an economic, sustainable CHP design. However, to achieve more heat recovery, more heat exchanger surface is required and heat exchanger capital costs increase. The engineering team must balance these competing factors of performance and capital costs. As a practical matter, exhaust temperatures should normally be kept above 300°F to prevent the formation of carbonic acid in the exhaust stream, which can lead to rapid exhaust duct/pipe corrosion and eventual exhaust duct/pipe failure (if condensing is anticipated, stainless steel exhaust ductwork/piping or other noncorrodible materials should be used). Note that diesel engine manufacturers have a lower minimum exhaust temperature limit of 250°F to prevent corrosion from condensation of exhaust. Also, sometimes, in order to be located in the proper temperature zone, the SCR must be installed in the middle of the HRSG tube bank and this system requirement must be coordinated with the HRSG manufacturer.

With an IC engine, as discussed, one source of heat recovery is from the jacket water (JW) typically at about 200°F, which represents about 30 percent of the fuel input energy. The percent depends on the type engine with turbocharged engines having a greater percent in the exhaust gases and naturally aspirated having more in the jacket water. Ebullient (with boiling) jacket water cooling systems operate at higher temperatures. The actual temperatures are dependent on the height of the steam separator above the engine and typically produce 5- to 15-psig steam. In order to minimize thermal stresses, engine manufactures typically limit the temperature differential (ΔT) across the engine to a maximum of 15°F. Controls must be included to prevent thermal shocking the engine from returning "cold" water back to the engine, where cold water is defined at a temperature less than allowed by the maximum ΔT . As an example, if the JW supply temperature leaving the engine is 200°F, the JW return temperature to the engine must be no lower than 185°F.

Another source of heat is the IC reciprocating engine exhaust which can be as high as 1200°F and represents almost 30 percent of the fuel energy. Approximately 60 percent of the exhaust heat can be recovered in an exhaust gas heat exchanger. While the exhaust pressure drop for an IC engine is not as critical in resultant prime mover performance

degradation as it is with CTGs, all of the same heat exchanger considerations discussed in the HRSG discussion above also apply to IC engines exhaust heat recovery with respect to the trade-offs between the amount of heat recovered, the pressure drop through the heat exchanger, the size of the heat recovery unit, and the capital costs required.

A hot water heat recovery unit (HW HRU), which is a gas-to-water heat exchanger, can be arranged such that the jacket water supply from the engine is fed to the HW HRU in order to increase the JW temperature by approximately an additional 10 to 15°F. Increasing the JW temperature may be helpful if a hot water-fired absorption chiller will part of the CHP plant design. This method can result in maximum JW delta-T of about 25 to 30°F. Attention should be paid to the flow rate of the engine cooling water. If the flow rate is too high, it can result in a lower than desired water temperature leaving the HW HRU. Depending on the use and relative demands of the recovered heat, some systems will split the jacket water cooling and the exhaust heat recovery into separate systems, providing, for example, the lower quality jacket water heat to a water heating system and the higher quality exhaust heat to an absorption chiller.

Lube oil heat represents about 5 percent of the fuel energy and is typically rejected via an engine thermostat at about 130°F. A 130°F hot water may be used for various low temperature uses including domestic water heating (or preheating), space heating, and swimming pool heating.

Other heat recovery uses and options are available including using the prime mover exhaust heat directly to fire an absorption chiller capable of providing simultaneous chilled and hot water, or directly to drive a solid or liquid desiccant system, or to heat air in an exhaust-to-air heat exchanger. As discussed in Chap. 24, another heat recovery option with CTGs that may eliminate the need for full-time steam plant operators and reduce many of the challenges associated with HRSGs in practice, is to use a nontoxic, nonflammable high temperature heat transfer fluid in a cascade fashion that maximizes heat transfer fluid delta-T.

Each prime mover should have its own heat recovery system, as well as a method for operating at full electric load output and still being able to reject all heat if required (e.g., during start-up and testing, or during emergency operations). For example, a steam condenser can be used for CHP systems with a HRSG to reject heat and an air-cooled radiator can be used for IC engine JW heat.

Alternative Heat Recovery Options

As discussed in Chap. 24, alternative heat recovery options are possible such as the hot-oil circuit that can maximize the log mean temperature difference (LMTD), and reduce backpressure losses. Claimed advantages include smaller thermal mass of hybrid steam generator which permits quick response to varying loads, low-pressure operation of high temperature heat transfer fluid recirculation loop which can eliminate the need for 24/7 stationary engineer code requirement, reduced CTG exhaust extraction coil pressure drop which improves CTG power performance, lower overall life-cycle cost, reduced installation time and operation complexity, reduced CHP system downtime, and reduced overall footprint.

Fuel Systems

While reciprocating engines may be fueled from a variety of gas and liquid fuels including: No. 2 diesel, natural gas, propane, landfill gas, digester gas (from wastewater treatment), and biofuels including biodiesel, as discussed in Chap. 2, almost 90 percent of the CHP

installations presently use natural gas (NG) as their primary fuel source, with fuel oil accounting for approximately 3 percent of installations and waste combustion accounting for another approximately 3 percent of the CHP system installations. The use of biofuels (solids, liquids, and gases) is growing, and, at this time, research is extensive into their use, and it is expected that in the future the use of biofuels will be more extensive. In fact, biofuels will likely have a major role in further enhancing CHP's sustainability as the fuel source will be essentially carbon neutral.

Typical CTG NG fuel systems components include: utility metering, pressure reducing stations, moisture separators, fuel filters, and fuel flow-control valves. As noted, CTGs often require higher-pressure natural gas (e.g., above 200 psig) than is available from the local gas supply main. Therefore, natural gas compressors are required to boost the gas pressure from the available NG system pressure to the pressure required by the CTG. If the NG compressors are installed indoors, they must be installed in a separate room with explosion-proof devices and leak detection and alarm. A backup compressor should be provided, so that the CHP system can still operate with the loss of one compressor.

The CHP system may require multiple NG pressure systems such as a high- and low-pressure NG system, one for the CTG and one for the duct burners (e.g., 250 psig and 30 psig), as well as a 5-psig system for any fired boilers and or fired absorption chillers. All of the metering and reducing stations should be located in a common protected area, usually just outside of the plant away from any air intakes.

Except for the fuel gas compressor and the required higher pressure, a NG fuel system for an IC engine is similar to a CTG NG system. Typical IC engine NG fuel system components include utility metering, pressure reducing stations, fuel filters, and fuel flow-control valves. An 8- to 10-ft-long surge pipe (a large diameter section of pipe) can be provided near the engine gas inlet to account for gas pressure drop upon initial start-up.

When fuel oil systems are used, either as a primary fuel source or as an alternate fuel source, or as an on-site backup fuel in case of NG curtailment, fuel oil storage systems are required. Any type of fuel storage must meet all of the codes, standards, and safety requirements for its location and installation. Some regions/municipalities limit the type and quantity of fuel stored as well the fuel storage tank locations with respect to property lines and adjacent occupancies. For aboveground tanks, spill prevention is often required to hold the leaking liquid fuel in the event of a tank rupture, and plans may need to be submitted to the authorities that outline what to do in the unlikely event of such a tank rupture. If storage tanks are located underground, double-wall tanks with leak detection may be required. In any case, it is important for all to minimize any release of raw fuel into the environment, whether the release is accidentally into the sewer or into a pristine waterway, or into the ground where fuel contamination can spread due to groundwater flows. Remediation after a spill is costly and time consuming.

Combustion Air

Proper combustion air system design is a critical component of sustainable CHP systems that use a combustion turbine generator as their prime mover. As discussed in Chap. 3, the power output of a combustion turbine decreases by approximately 0.5 percent for each inch of water pressure loss across the combustion air-inlet system. The combustion air system can include an outside air (OSA) louver (if the CHP system is located in a building), inlet-air filter, inlet-air duct silencer, ductwork, and combustion-turbine-inlet

cooling (CTIC). CTIC, for example, using either a cooling coil or evaporative cooling, counteracts the negative effects of increased heat rate and reduced capacity caused by inlet-air temperatures above the nominal rating temperature of 59°F. Typically, the CTG inlet-pressure drop is limited to no more than 3 in of water column (wc), so the design engineer must layout the proposed CHP plant and combustion air-inlet ductwork system carefully to avoid unnecessary changes in direction which will increase the air-inlet pressure drop. Smaller angle changes in ductwork result in lower pressure drops than do larger angle changes (e.g., all else being equal, a 90° elbow has more pressure drop than a 45° elbow). Ductwork velocity, which is a function of ductwork size for a given combustion air flow rate, is the controlling variable with respect to pressure drop through the combustion air-inlet system, as for a given system, the pressure drop varies with the square of the air flow velocity (double the velocity equals 4 times the pressure drop).

Combustion air systems are not as critical with IC reciprocating engines as they are with CTGs; however, engines still require cool, clean air for combustion. Like a CTG, an IC reciprocating engine combustion air system can also include an OSA louver (if the CHP system is located indoors), inlet-air filters, ductwork and an inlet-air duct silencer to prevent engine noise from translating out the ductwork to the outside.

Exhaust Systems

On a CTG CHP system with relatively high mass flow rates, similarly to combustion air-inlet systems, the exhaust gas system pressure drop must be kept as low as possible, within the manufacturer's maximum allowable backpressure limit, in order to minimize the reduction of combustion turbine capacity. The maximum allowable CTG backpressure is about 8 in of water column, and similarly to the combustion air system, pressure drop can be minimized by proper duct sizing, minimizing unnecessary duct twists and turns, and by selecting the heat recovery device for a relatively low pressure drop. A CTG exhaust system typically includes the exhaust ductwork, emissions control equipment, the HRSG or heat recovery heat exchanger, continuous emissions monitoring system (CEMS), exhaust bypass valve (if allowed), exhaust silencer (if required) exhaust stack, and expansion joints to help accommodate thermal expansion. The ductwork must be insulated to keep in the heat to be recovered (i.e., minimize heat loss), and to protect operating personnel.

For a turbocharged IC reciprocating higher engine backpressures up to almost 30 in of water column are possible without as significant of performance degradation as compared to a CTG. However, sustainable design still entails designing for the minimum economical pressure drop. Typically, black steel pipe is used for IC reciprocating engine exhaust as compared to sheet metal ducting for CTG exhaust. Dependent upon emissions treatment methods employed, some sections of stainless steel pipe may be required. In addition to the exhaust pipe itself, which ultimately conveys products of combustion to the outside, typical IC engine exhaust components include: emissions control equipment; the heat recovery heat exchanger; continuous emissions monitoring system; exhaust muffler, exhaust stack, and expansion joints to help accommodate thermal expansion.

An expansion joint should be provided at the IC engine itself to allow for thermal expansion and to prevent forces and stresses from acting on the engine exhaust flange. The hanger and seismic supports should be determined, as well as the amount and direction of thermal expansion, in order to accommodate that expansion with, for example, expansion joints.

Like CTG exhaust, the IC engine exhaust pipe, which can reach 1200°F must be insulated to retain heat and to protect operating personnel. The exhaust pipe should be sloped down, away from the engine so that any condensation (which can form during engine start-up and shutdowns) does not drain back into the engine.

Temperatures should be read by the control system (also provide local gauges for operator use) at the engine exhaust, before and after a heat exchange device, and at the inlet and outlet of the catalyst/SCR system. Some of these temperature sensors can be combined, for example, the engine exhaust temperature might be the same as the catalyst inlet temperature.

Emission Controls

Emission controls are a critical system for a CHP plant affecting the CHP systems ability to operate and to be sustainable. The type of emissions control system required will, as discussed, depend on the prime mover(s) to be used, the expected emissions levels from the selected prime mover(s), as well as the maximum emissions allowable by regulating authorities for the proposed CHP plant. Emission controls are discussed in detail in Chap. 7 and permitting requirements are discussed in Chap. 12.

Key issues for the engineer include helping to ensure that catalysts are maintained at the proper temperatures. Engine exhaust temperatures can vary with load and the CHP plant system must be capable of maintaining the proper temperatures to prevent damaging or destroying very expensive catalysts. Also, if minimum temperatures are not achieved, catalysts will not perform effectively. Also, as part of the exhaust system, provisions must be made for emissions equipment and its support and for operator monitoring and maintenance. Another important design issues with respect to the emissions control system is the storage of ammonia, often in the anhydrous form, which may have code specified quantity and location limitations.

Thermal Uses

As discussed throughout this book, CHP derives its economic benefit from the recovery and productive use of waste heat that otherwise would be rejected to the atmosphere. Therefore, fully utilizing the heat as much as possible, not only on a peak design basis but also throughout the year, is critical to achieving sustainable CHP. Of course the amount of heat that can be effectively used at a facility is a function of the facility loads and the size and type of the prime mover employed (and the resultant thermal-electric ratio), which hopefully was well studied, planned, and sized as described earlier in this book. Otherwise if, for example, the prime mover was oversized and there is not enough thermal demand, there may be little the design engineer can do to avoid future heat dumping. However, assuming a well-studied and planned CHP system, the CHP design engineer still needs to plan for a variety of thermal uses and should account for periods of low load. As noted, some thermal uses include

- Additional power (combined cycle)
- Space heating
- Space cooling (using an absorption chiller, for example)
- Domestic hot water production
- Swimming pool heat

- Desiccant dehumidification
- Product drying
- Process heating

Additional power can be produced, for example, by using steam generated in a HRSG to drive a steam turbine generator. The steam turbine generator can either be a condensing type or backpressure turbine type that reduces steam pressure to a pressure required by another system (e.g., from 250 to 15 psig required by single-effect absorption chillers). Space heating, for example, can be provided with steam or hot water (HW) coils, and hot water can be generated either from steam in a steam-to-hot water heat exchanger or from a JW-to-HW heat exchanger. At some facilities, high temperature hot water (HTHW) is generated at the CHP plant and circulated to facility buildings, where the temperature is stepped down at a building in a HTHW-to-HW heat exchanger. However, generally low temperature HW (LTHW) systems are preferred as they are safer, have less thermal expansion challenges, and work well with IC reciprocating engines.

Chilled water for space cooling can be generated by a number of methods as described in Chap. 4 including: single- or double-effect absorption chillers using lithium bromide or ammonia; adsorption chillers; and steam turbine-driven centrifugal chillers. Also, as discussed in Chap. 4, a single-effect absorption chiller is capable of being fired with low temperature HW (less than 250°F) but typically requires temperatures above 200°F to be cost-effective. Double-effect absorption chillers typically require 125-psig steam or equivalent high temperature fluid and therefore are only used with CTG CHP systems. Likewise, steam turbine-driven centrifugal chillers require medium-pressure steam and therefore are also only used with CTG CHP systems.

Providing a variety of thermal uses with a correctly sized CHP system will enable the CHP plant operators to maximize the use of available heat recovered. The CHP plant operators will also sometimes be required to make equipment operations choices, for example, would it better to produce additional power or to produce additional cooling or to use the heat instead for space heating. Later chapters and case studies describe valuing the CHP products and costs and determining which thermal output has the greatest value. Of course having to make a choice where to put the heat is vastly superior to not having a choice and being forced to dump heat or to turn down or to shut down the CHP plant altogether.

Electrical Interconnection and Protections

The proper electrical interconnection, generator and facility electrical system protections and safeties, system grounding, as well as generator paralleling controls (assuming electric utility interconnection) that meet all code and utility interconnection requirements are key for successful CHP operation, and these issues are discussed in detail in Chap. 11. As with the mechanical and thermal elements, the type of CHP system has an effect on the CHP electrical design itself. The generator type must be compatible with the existing electrical system and transformers and switchgear are typically required. The generator voltage usually matches the highest system voltage needed at the facility to minimize electrical resistance losses. Often, the local utility will require a detailed interconnection agreement that will, for example, specify minimum import, system protections, and grounding requirements. Protections must also be in place, for example, to account for voltage spikes and sags, as well as a loss of power.

Operational Flexibility

As discussed, having a variety of uses for the thermal output improves operational flexibility. Likewise, having a number of pieces of the same equipment to meet the demand improves operational flexibility and can allow for equipment backup so that operations will not be impacted by the loss of a single piece of equipment. The number and size of any selected CHP equipment item depends on the size and nature of the loads served (e.g., what is the peak load and how does it vary by day and season), on the unit sizes available in the marketplace, and depends on the cost to provide multiple units, as multiple units always cost more than a comparable single unit but can offer greater CHP plant operational flexibility. In contrast, however, the greater the number of equipment units, the less expensive it is to add a backup unit. Note, it is often not economically feasible to provide a backup prime mover generator, and the local utility typically provides electric power backup. Exceptions to not providing a backup prime mover include, for example, manufacturing processes, where loss of power could damage valuable product, and revenue generating operations, where loss of power could cause severe economic loss (e.g., lose all of the guests at a hotel and pay for their trouble). Another advantage of using multiple smaller pieces of equipments is the ability for the system to operate efficiently at part load or at less than design conditions. For example, if a cooling water flow rate is required to be only 30 percent of the design flow rate at given condition, than operating one of three pumps at 100 percent flow rate will likely be more efficient than trying to operate one of one pumps at 30 percent flow rate. Turn-down will also improve with multiple equipments.

Plant Equipment Location and Layout

Layout of proposed CHP equipment is an important part of the CHP design process. A number of factors, including access for maintenance must be incorporated and reconciled. First, all applicable code regulations must be satisfied with respect to distance from property lines, for example, for fuel or ammonia storage, as well as for the proposed exhaust stack. The prime mover and generator, as well as other plant equipment, should be arranged to minimize the length of interconnection piping and conduits to fuel supply, power connections, and thermal points of connection. Connection to the electrical power distribution for the facility served is also a key issue.

Further, each piece of equipment has a minimum maintenance envelope that must be kept clear for any required servicing, maintenance, and/or repair, and the maintenance envelopes need to be incorporated into the design layout.

Electrical panels and switchgear also have minimum clear areas in front of (and sometimes at the back of depending on maintenance access points) the electrical equipment, with the required clear distance depending upon the electrical equipment voltage (greater clear distance is required for higher voltages).

An operator's room with clear view to all the major components is a clear asset of a good layout.

Maintenance and Servicing

As noted, key maintenance and servicing issues need to be kept in mind during the layout of the proposed CHP plant. For example, CTG engine replacement typically occurs every 30,000 hours or so of operation. Usually, in order to minimize downtime, a replacement engine is provided, and the old engine is rebuilt for a new customer. Space must be provided to remove the engine from the CTG, and then easily to remove

the engine from the CHP plant. Overhead hoists and cranes can be incorporated into the plant to ease maintenance operations including pulling heads on IC reciprocating engines. CTG engine washdown and provisions should be made for storage of the washdown cart as well as its use.

With a chiller or a HRSG, provision must be made for tube pull and tube cleaning. On a chiller, the tube pull area often equals the length of the chiller. Vapor compression chillers and fired devices (e.g., boilers) typically require an area separation due to fire codes (i.e., a fire rated wall between the latter equipment types). It must be understood by the CHP design team that everything eventually breaks and needs to be repaired. CHP plant and equipment layout needs to account for this eventuality.

Future Expansion

Where the proposed initial CHP system includes provisions for owner-operator anticipated future expansion to meet future load growth (e.g., due to owner-operator programmed additional buildings or processes), provision in the initial installation should include accessible points of connection (POC). This allows additional equipment to be installed with only minor disruption to existing CHP plant operations.

Planning for future expansion may involve oversizing headers and distribution piping, power and structure for the future expansion, and includes providing space for the future equipment or a planned path for expanding the plant to provide that space. Planning for future expansion includes capped connections with shutoff valves as future POCs. Note that oversizing the headers and piping may be partially self amortizing in term of reduced pumping power (energy consumption) requirements. The CHP engineering team should always consider as an integral part of its initial design that whatever is constructed today will require some changes, and should plan for 10, 20, even 30 years or more following initial construction during which utility infrastructure expansions may be needed from time to time. The planning horizon for an energy plant in Europe is often 100 years.

Future planning considerations are especially relevant for building underground cable and piping systems, and should include some provisions to allow installation for additional prime mover generators and heat recovery needs. The design and construction of future equipment pads should wait, however, for installation of the actual equipment as codes and specific equipment design may change in the future.

Noise and Vibration Attenuation

Depending on the type of prime mover employed, location of the proposed CHP plant, as well as the distance to surrounding neighbors and their occupancy (e.g., manufacturing or residential), noise and vibration mitigation may be required. In a two-dimensional analysis (which is the case where noise transmission is analyzed in plan view and there are no noise receptors above or below the CHP unit), noise level drops by the square of the distance from the source. Low frequency rumble can carry farther than higher pitched sounds. Therefore, the farther away the proposed CHP system is from a noise receptor, the lower will be the sound level measured at the receptor. If the CHP system is to be located in a noise sensitive area (e.g., next to campus dormitories and adjacent residential areas), it is recommended to include an acoustical engineer as a member of the CHP design team. Noise can be transmitted by either direct "breakout" at the equipment or by translating down ducts and pipes. Also, noise and vibration can be transmitted directly through pipe, duct, and supports attachments. Noise mitigation addresses all of the noise transmission paths.

If the project is near critical sensitive equipment like electron microscopes in a nearby building, extensive inertia bases may be required for the prime mover equipment.

Direct equipment breakout noise can be attenuated through the use of equipment enclosures, where, for example, the CTG or IC engine generator is installed in its own manufacturer supplied enclosure. In addition to an engine enclosure, a building can be provided to not only reduce noise levels outside the plant, but also protect the CHP equipment from the outdoor elements. When a CHP plant building is involved the building elements also can provide some noise attenuation. Sound-rated doors and windows must be incorporated, and the inner walls of the CHP plant can be provided with an acoustical liner (provide a screen mesh for liner protection). Any opening into or out of the CHP plant such as vents and louvers must also be acoustically treated. Acoustical louvers can be provided on all air intakes and an inlet-air duct silencer should be used on any combustion air-inlet system.

Heat recovery equipment helps to reduce the exhaust noise level, but an exhaust muffler will likely still be required with an IC reciprocating engine. To help minimize the adverse effects of vibration, vibration isolators are used on equipment and expansion joints are used at points of connection to reduce vibration transmission, to account for any small pipe/equipment misalignments, to help accommodate thermal expansion, and to prevent excessive force and/or stress from being applied to equipment. Excessive ambient noise may also require filing for permit as discussed in Chap. 11.

Plant Controls/Integration

Plant controls, which include monitoring, measurements, equipment starting and stopping, alarms, and modulating control are an important, if not critical, piece of a successful, sustainable CHP plant. As discussed in Chap. 16, an exceptional operator may not need many visual readings to know if the plant is operating properly; he or she can tell by the nature of equipment sounds, by the feel of vibrations, and by the touch of a hand (e.g., to detect if a bearing or motor may be overheating). On the other hand, in today's world of modern computer-based, direct digital controls (DDC), making provision for automatic monitoring and trending of operating points can make it easier for CHP plant operators to evaluate and diagnose (i.e., to troubleshoot) any future system problems, as well as make it possible to optimize CHP operations. In fact, modern controls systems can adapt to changing conditions and parameters (adaptive control) as well as warn ahead of time of pending failures by trending system parameters.

The prime mover and generator will have its control systems, for example, a constant speed governor to maintain a constant engine-generator speed (rpm) and to modulate the fuel control valve to match generator load. The electric power generator will also have its own safety controls and paralleling system. The balance of the CHP plant must be controlled and operated by the plant control system. Ideally, many of the engine and electrical system monitoring points are incorporated into the plant control system (see Chap. 17). The control system needs to be fast acting and capable of real-time PID (proportional, integral, derivative) loop control. Many CHP plants do not have operators located at the plant, and these plants must not only be automatic, but remote monitoring and alarm needs to be provided to an operator at a remote point.

As previously discussed in this chapter, one of the first steps in planning for the design of CHP plant control systems is to develop for each system a piping and instrumentation diagram (P&ID), which shows all major equipment, valves, instrumentation, and proposed method of control for that system (e.g., the HW heat exchanger steam

supply valve will modulate to maintain a HW supply temperature of 140°F). Often, as a second step, a point list is prepared outlining all of the CHP plant's: temperature, pressure, and flow measurements; consumption meters (power, Btu, water); points of modulating control (e.g., CHW pump speed or steam control valve position); valve position; equipment to start or stop; equipment status (on/off); as well any alarm inputs and alarm outputs (e.g., catalyst temperature of 1100°F is an alarm input and sounding the alarm itself is an alarm output). The point list should also indicate any required calculated points, such as CHP or Federal Energy Regulatory Commission (FERC) system efficiency, or the value weighted energy utilization factor (please see Chap. 17).

Flexible controls that are well documented, easy to troubleshoot, and easy to modify are of great benefit to knowledgeable CHP plant operators. Future plant operating constraints are likely to change along with facility business needs. Therefore, flexible controls and well-planned instrumentation can assist in facilitating future additional needs.

Sequence of Operations

Understanding how the proposed CHP plant will operate as well as the nature of the facility loads (peak, profile, and seasonal) is critical to developing a workable sequence of operations that will help the proposed CHP plant be sustainable. The developed available thermal uses will also impact the proposed sequence of operations. For example, will the proposed engine generator (or CTG) be used to meet the facilities base electric load and therefore always be fully loaded? Or, will part load operations need to be considered? Can all of the heat be used or will some heat dumping be required? When and where can heat be used? At a higher level, decisions can be made regarding which equipment would be most beneficial to operate. Chapters 17 and 18 provide some guidance regarding operational metrics and sustainable CHP plant operation.

Intangibles

As a CHP facilities director once said, good karma is the key to selecting a CHP design team that works effectively, communicates well, and on a good day has fun, and will result in a better CHP design. Pragmatic, holistic approaches may prove more effective than overdesigning the central CHP plant. For example, it may prove more cost-effective to concentrate on improving the distribution system than initially requiring oversized distribution pumps. It may be more cost-effective to get higher delta-T coils and better control valves than to add more chillers. Retro-commissioning building controls may free up large amounts of capacity that can be better utilized elsewhere (e.g., simultaneous heating and cooling is shockingly common).

Specifying classroom and hands-on training as a part of every major equipment purchase is often vital to achieving sustainable CHP plant operations. Specifying thorough start-up and commissioning provisions can go a long way to ensuring that CHP plant equipment and systems operate as designed and can make more likely a successful transition from construction to operations. The commission team should be brought on board at the beginning of the design processes (programming). The benefit that CHP system operators obtain from commissioning and training is invaluable in their understanding of how best to achieve profitable and sustainable CHP plant performance in a challenging energy use and cost environment.

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Electrical Design Characteristics and Issues

Kelly J. Mamer

David C. Rosenberger

Jeffrey S. Hankin

The maximization of CHP energy use requires an extremely well-designed mechanical and electrical system, with a number of design considerations taken into account for each interconnected system. Regarding the electrical system, the risks for a poorly designed system go far beyond system failures, as costly and debilitating as that may be. For example, utility companies have detailed requirements for export of owner-operator-generated power onto their grid. This becomes extremely important in the event of a fault on the utility side of the line, with the potential that the CHP system may be feeding back into a fault and creating a scenario where life safety is at risk. CHP systems have many applications and options, and the generation of electric power is typically a key to the applicability of these systems. However, the electrical system design must allow the CHP facility owner to utilize the generated electric power in a safe and efficient manner.

This chapter discusses a number of specific electrical design issues; the next few paragraphs are a summary of these issues. One issue is the electric power generation itself and its delivery to properly sized, configured, and protected switchgear equipment. The principal factor, excluding safety concerns, among all requirements of a CHP system is redundancy and reliability at the CHP plant and further upstream when distributing electrical power onto the utility grid. A robust and redundant electric power system requires switchgear which allows the CHP plant operator various options for connection and maintenance of the prime mover as well as for an efficient distribution system for downstream loads.

In concert with the power distribution equipment, a well-defined control and energy management system works to optimize plant energy demands as well as help improve the efficiency and availability of the CHP plant. As past CHP and other industrialized plants experience shows, investing in a robust and reliable control and energy management system has many significant operational and economical advantages.

Additionally, careful planning and consideration must be given to safety issues of a CHP system to ensure equipment vitality and personnel safety. From grounding and bonding to relaying protection for system interconnection, every CHP system design must take into account all opportunities to introduce safety and protection measures. There are different ways to ground the electrical system, each with advantages and disadvantages. Certain methods for electrical bonding are requirements of the National Electric Code (NEC) and these are discussed later in greater detail.

As discussed in Chap. 2, CHP systems are utilized in a wide variety of facilities, from industrial plants to health-care campuses to military installations. The various users of the electrical power downstream of the CHP facility are not particularly interested in where their power originates; rather, users are more concerned that the power is available when and where needed and that it is of high quality. The electrical design of a CHP system, therefore, must plan for voltage spikes and sags, harmonics, power interruptions, and other power quality issues that traditionally challenge large power generating and distribution systems. Particular challenges in power quality design arise due to the protection system effects with multiple relays causing additional power surges. However, steps can be taken to ensure clean power into the distribution system and are discussed later in this chapter.

Unless the facility is designed to always operate in “island mode” separate from the electric grid, interconnection between the CHP facility and the local utility is a critical part of a CHP system; as noted above there are many codes and standards governing this interconnection. Often, power generated by a facility from their CHP system is meant as a supplement to the power they purchase from the serving utility. This means both power sources are typically feeding into the same downstream distribution system at the same time. Under this condition, utility companies assume the risk that a fault in a facility’s electrical system may propagate into the utility power grid unless appropriate protection measures are put into place. Electrical designers of CHP systems must work closely with the local utility company to ensure those protection measures acceptable to the local utility are in place.

Finally, any CHP plant design and construction should have well-developed and thorough systems start-up and commissioning plans. It is a necessity to ensure the entire electrical distribution system is operating in its optimal condition, and strong commissioning of a CHP project will ensure that the proper choices were made during system design, equipment selection, and installation.

This chapter serves as a general overview of electrical design considerations for a CHP facility. A separate book could be written about these electrical issues to capture the detail each of the issues deserves. The last portion of the chapter includes a simple example of an electrical system for a CHP facility and a list of resources, and an electrical designer is encouraged to dig more deeply into the items covered in general detail in this chapter.

Switchgear Design Considerations

Switchgear design for a CHP plant must account for two separate but equally important items: distribution and control. Distribution of the electrical power generated by whichever type of CHP generator utilized throughout the facility is at the heart of CHP system. No matter what the reasons are for installing a CHP plant at a facility—base load power, possibly standby power, isolated feed, peak shaving, or export—the switchgear

provides a connection between the CHP generator and the facility being served, and at times connection to the utility power grid as well. The switchgear includes more than just circuit breakers or load interrupter switches. It may also include transformers depending on the output voltage of the generator and the utilization voltage for the facility or utility. It will certainly include some level of controls to ensure multiple power sources are protected or a facility is using the power in the most efficient way possible.

Selection and Design

Before discussing the switchgear selection criteria for each of the operational modes, this section summarizes the basic fundamentals found in any switchgear design. First, there are connections into the conductive bus bars within the switchgear from both the CHP source and the utility source. Whether the connection is via a solid state circuit breaker, a load interrupter switch, or some other type of switch is dependent on the whether the connection is low voltage or medium voltage and what type of protection and coordination characteristics the designer includes. There are also distribution circuit breakers which again, can be at either low or medium voltage that serve loads downstream from the main switchgear. Also, there is a feed to the CHP electrical equipment (i.e., source). Depending on the type of prime mover, this may include fuel supply pumps, water injection pumps, or generator starter motors.

The electrical power generated by a CHP system is utilized in different modes of operation and each has different switchgear design considerations. The most basic is in a stand-alone (isolated feed) configuration, where the CHP is the only source of power for a facility, or portion of a facility. This switchgear design is the simplest, because there is no paralleling between multiple sources required. The CHP generator is connected to the switchgear in a manner similar to any utility source, via a load interrupter switch, a vacuum circuit breaker, or a molded case circuit breaker. The CHP generator may generate power at medium or low voltage, and the switchgear connected to the generator may also be at medium or low voltage. Ultimately, of course, the voltage will be transformed to whatever the facility requires, but this is not an atypical installation.

However, several other modes of operation require more specialized distribution and control. These modes of operation are defined as follows:

- *Standby power.* If the generator is used only to provide power in event that the primary power source (typically the utility) is not available.
- *Peak shaving.* When a facility wishes only to purchase a specific amount of energy from a utility, either for contractual reasons or economic ones, it will use energy from its CHP generators to supplement that utility power when its energy needs exceed that which they receive from the utility.
- *Base load.* In this case, a facility will use the energy generated by the CHP plant up to its maximum capability and will only use a separate utility source when its needs exceed the capacity of the CHP plant. It is fundamentally the opposite of the peak shaving mode.
- *Export.* In this case, excess energy generated by the CHP plant not needed to serve the CHP plant loads will be transported back onto the utility grid.

In any of these applications, the switchgear must be capable of being fed by both a utility source and the CHP source. Each of the incoming energy sources are capable of

feeding into the switchgear bus at the same time, and because of this there are a number of considerations and capabilities which should be taken into account for the switchgear serving a CHP system.

One such consideration that warrants attention is the type of bussing in the switchgear. If the bus is physically separated into two or more discrete sections for various design reasons (e.g., load distribution), these sections would require connection to each other via a tie circuit breaker. In this example, the main circuit breakers directly upstream from the energy sources are both interlocked with a tiebreaker so that the incoming feeds are physically separated at all times. Another possible method of configuring the switchgear to accommodate the multiple source input is paralleling switchgear, in which all incoming sources feed the same physical bus at the same time. To effectively utilize paralleling switchgear, the switchgear must have a synchronizing system which ensures that all electric power generated is operating together at the same rated voltage, frequency, and phase.

In both of these cases, the switchgear and its associated distribution system will feed all downstream loads if sufficient energy is available from a combination of utility and CHP sources. Prime mover load control in the switchgear will ensure that power from all sources is balanced and efficient. However, if one of the sources is lost, or for some other reason inadequate energy is generated to serve the facility (e.g., voltage irregularities or low frequency), load-shedding will be required to control the ability of the switchgear to drop or shed certain lower priority electric loads.

Another capability to be considered in switchgear design includes voltage and reactive power control, which refers to controlling voltage regulation delivered by each energy source and automatic adjustments for varying reactive power levels. Remote overcurrent and protection controls, another design consideration, includes either automatic on/off and reset capabilities of overcurrent devices or manual capabilities from a remote location. Each of these key elements of switchgear design should be carefully considered by the CHP designer to ensure maximum optimization and safety of the CHP system.

Utility Source Characteristics

Utility power grids typically have a capacity that can be as much as 1000 times that of a CHP facility load, even for an especially large facility. In fact, to the CHP facility the utility grid appears to be practically infinite in size. Therefore, in the design of power distribution systems at the utilization point where a building or facility is connected to the grid, it is common to base the design on an infinite bus characteristic such as constant frequency, constant voltage, and infinite available current. In reality, of course, available current is not truly infinite but it can be modeled as such to simplify fault current calculations. However, unlike the utility grid, on-site generators do have finite limitations. Their available fault current is predictable; the available short-circuit current from a small generator (in the range of 100 kW) is about 10 times the rated full-load current of the generator immediately after the initiation of the fault, and drops to about half of that in about 0.1 second. Circuit impedance (resistance of the cabling) further attenuates the available fault current. The important point is that while the utility grid can be considered an infinite bus, the on-site generators definitely cannot and the CHP designer must take that into account when selecting and designing key system design components.

Large loads that are applied to a generator (either an increase or a decrease in load) are called step loads. Any generator will react with a decrease in voltage and frequency

upon a step load increase, and conversely with an increase in voltage and frequency upon a step load decrease. If the step load is large (approximately 20 to 25 percent of the generator set rating) the transients seen by the generator will be measurable and may cause a trip of the generator breaker. On the other hand, if the step load is small (less than 5 percent of the generator rating) the transients will be barely noticeable. When the CHP generator is operating in parallel with the utility, the step load transients as seen by the generator will be small, because the utility is, again, practically an infinite bus. However, if the system is designed such that the CHP generator may see large step loads (the addition of an electric power-driven chiller, for example) when not in parallel with the utility, the system must be designed to be able to handle the large transients that will occur. Alternatively, the distribution system must be designed to limit the size of step loads, via variable frequency drives or soft starters.

Black start Generator

Switchgear also needs to allow for connection of another special power generation source in large CHP plants (greater than 1 MW), particularly those using a combustion turbine generator. In a CHP facility of this size, a potential (and not uncommon) situation is that the facility is receiving all of its energy from the CHP source because the utility source is unavailable (perhaps, due to a utility system-wide outage). If a subsequent fault in the CHP system temporarily shuts down the plant, the plant operators will desire to restart the CHP generator(s) as quickly as possible since at that particular time it is the sole source of power to the facility. However, because the utility source is unavailable, there is no power for the pumps and starter motors required to restart a combustion turbine generator. Therefore, a separate black start generator is a critical design consideration and a must to the electrical system. This generator condition is called "black start" because its only use is to provide starter power for a separate generation system in event of a blackout. The black start generator and an automatic transfer switch connected directly to the CHP plant motor control center is another aspect of the switchgear design needing consideration.

Controls

To optimize a CHP system in a mode in which both utility and CHP sources feed into the switchgear, the control system has a major role in controlling the interaction between utility (purchased) power and internally self-generated power. For example, in a peak shaving system the demand for utility power must be monitored to ensure that the limit for a given period does not exceed whatever the contract value set between the utility and the facility. Accomplishing this may entail a load-shedding scheme, where the switchgear controls automatically open predetermined circuit breakers (i.e., loads) if the CHP system does not have enough capacity to carry demand peaks above and beyond the utility contracted amount.

There are a number of possible components in a CHP switchgear application related to controls, power quality optimization, and energy management. Tie circuit breakers and demand controls were mentioned earlier. Another key component is remote breaker control, which allows an operator in the CHP control room to open or close either input or distribution output circuit breakers. This allows quick response by a system operator, when sometimes monitoring the system 24 hours a day, to a potential problem without requiring maintenance staff to be dispatched to the electrical room. Yet another option is demand load metering on all of the distribution circuit breakers. Having precise

information for all individual distribution circuits, rather than just a measurement of overall distribution load, allows the operator or system to make dynamic decisions on load-shedding or load-addition. Demand load metering can potentially be combined with control of the CHP generator output. If, for example, a real-time or life-cycle economic calculation determines that the energy purchased from the utility could be increased without a large marginal cost, the CHP generation can be decreased to reduce fuel use or better optimize the CHP output.

Engine/Generator Controls

One significant component of a control system particular to CHP systems is the engine control system and its interaction with switchgear where it connects to the utility. The major elements of the engine control system are the governor (ANSI Device #65) and its accessory load controller (#65C). The major elements of the generator control system are the voltage regulator (#90) and its accessory volt-ampere reactive (VAR)/power factor control (#90C).

Most commonly, the CHP engine is driven at a constant speed, maintaining a constant generator output frequency regardless of the load. This is more commonly known as an isochronous system. In simple terms, the electronic governor senses the load and varies the fuel supply to the engine to produce the necessary output and maintaining constant voltage is a function of the amount of excitation current available to the rotating field. When two or more engines are operated in parallel, the electronic governors will control the sum of the total load produced by each generator set. In addition, the generator controls vary the excitation to each generator so that in a paralleled condition each generator unit shares the total reactive load (measured in kvar) proportionally to its real load (measured in kVA).

As an example, consider a situation in which two 500-kW generator sets are operating in parallel with an additional 1000-kW unit, for a total system capacity of 2000 kW. Each of the 500-kW generator sets will provide 25 percent of the system load, varying depending upon the downstream requirements. The generator sets will also carry 25 percent of the reactive load. The 1000-kW generator set will carry the remaining 50 percent of the total real and reactive load.

The governor load sensor controls the governor and subsequently, the fuel supplied to each single engine. This level of control ensures the engines will maintain at constant speed as the loads vary. When multiple CHP generators are operated in parallel but not connected to the utility, these governor load sensors are all part of the load-sharing signal loop so that all generators share the load proportionately. But when the generators are operated in parallel and connected to the utility, there is an accessory loading control which is switched into a load-sharing signal loop. This accessory control is continually monitoring the utility input to the CHP system and this has a significant effect on the generator outputs. The accessory control function combines with the CHP control system and responds to the total system demand for both heat and electrical energy. In other words, the load that the CHP generators share proportionately will vary based on the utility contribution which in turn varies as determined by the accessory loading control. This functionality may likely add complexity to the control system. For example, in large systems that are in parallel with a utility infinite bus, droop control is sometimes used. Droop control is a function which allows for a slight drop in engine speed with an increase in load. This slight drop in engine speed allows for optimum operating efficiency of the CHP plant. In this scenario, the engines use only enough fuel to satisfy the demands for energy programmed into the loading control.

The voltage regulator controls the generator excitation to provide the set-point voltage output for a single unit. When generators operate in parallel, and are not connected to the utility system, the set-point bus voltage is the same for all units. The voltage regulator current transformers for all parallel generators are connected in series so that all regulators see the same load-sharing signal, and are called cross-current compensation. The voltage regulator controls the excitation so that each unit shares proportionately the total reactive load. This series loop is to the voltage regulator what the load-sharing loop is to the governor.

However, when the generators operate in parallel with the utility infinite bus, the terminal voltage (voltage at the junction between generator and utility inputs to the switchboard) is determined by the utility voltage. In this case, a VAR/power factor control system becomes critical to regulate reactive power loading for each generator (preventing excessive generator current). The most effective operational mode is to control excitation as a function of system power factor, causing reactive power generation to track real power load, which in turn minimizes the total power (kVA) and generator current for any facility load. The power factor set point for the VAR/power factor control system should be between 0.8 and 1.0, with the midpoint of 0.9 recommended for system optimization.

Environmental Requirements

All electrical equipment is sensitive to the environment in which it operates. Temperature gradients and moisture have an effect on even the simplest electrical equipment. For complex switchgear such as that typically found in a CHP installation, environmental requirements for the electrical room are even more critical as noted below.

Most electrical equipment for a CHP system are located in rooms or dedicated equipment areas and are indoors in close proximity to the prime mover/generator and related mechanical equipment such as boilers, chillers, or heat exchangers. This means moisture is likely more prevalent in the atmosphere than within a typical electrical switchgear room. Moisture is the chief adversary of electrical equipment because over time it can cause corrosive effects on circuit breaker contacts and wiring connections, thus leading to potential early and dangerous failure. Additionally, in CHP facility switchgear there will likely be programmable logic controllers (PLCs), integrated relays, and other miscellaneous electronic equipment that is also extremely sensitive to moisture and corrosive environments. It is critical that the switchgear be designed and specified with extra gaskets and seals and that the switchgear be placed in a room which is also well sealed and/or isolated from the heavy mechanical equipment. Of course, if the switchgear is placed outdoors, this can be an even greater concern. The switchgear will need to be specified with a minimum NEMA 3R enclosure as per any outdoor equipment. However, the designer should give consideration to specifying NEMA 4X (or IP56) ratings—or preferably, working with the facility designer to find an indoor location.

Similar considerations must be given to room temperature. The room must be kept cool enough so that the temperature rating of the sensitive electronic equipment is not exceeded and so that electrical wiring does not have to be derated due to high temperatures. Often, the switchgear and associated distribution system may include transformers which generate significant heat, so it is even more critical to ensure the room design includes supplemental cooling and exhaust. However, it is important to note that care must be taken to ensure temperature gradients within the room are not too large.

If cooling systems are not well designed, or switchgear built that doesn't allow for proper air circulation, temperature gradients can cause moisture similar to the way warm weather fronts and cold weather fronts cause precipitation where they collide.

Grounding Considerations

A CHP generator serves a facility with energy separate from a utility and has no direct electrical connection to the supply conductors originating from the facility. By this definition, it is considered a separately derived system by the National Electrical Code (NEC). This has a number of implications for grounding and bonding the CHP generator and plant with the facility electrical distribution system and these will be discussed in greater detail later in this section. Before that, however, we will discuss the various grounding system types and provide guidance on selection of which grounding system to choose.

Grounding System Types

The most common type of grounding system is a solidly grounded wye system. Typically, the primary feed is delta-connected and the secondary is wye-connected, and there is a solid connection between the ground on the primary and the center of the wye on the secondary. In this configuration, the grounded (neutral) conductor in the secondary carries single phase or unbalanced three phase current. This grounding system is very common because it works in applications where both three-phase motor loads and 277 V per single phase lighting loads are needed.

In a fault condition, the available short-circuit current between a phase conductor and ground is dependent on the impedance of the distribution system. In addition to the conductors making up the pathway between the fault and the ground source, the total impedance would also include the impedance of the primary generation source.

Another common grounding method is impedance grounding, which is similar in concept to the solidly grounded wye system in that there is a connection between the ground on the primary and the center of the wye on the secondary. However, in this case, an impedance source (i.e., a resistor) is inserted in this connection pathway. If the resistor is large, it is considered a "high-impedance" grounded system and the fault to ground will be a low current value, so low in some cases that an overcurrent device will not open. When a small resistor is used, it is a "low-impedance" grounded system. In this case, the ground fault will be large enough to trip an overcurrent device, but the value will still be low enough for a relaying scheme typical in CHP switchgear to handle.

An alternate to a grounded system is an ungrounded system. In this case, there is no physical connection between the phase conductors and ground. Similarly to an impedance grounded system, the fault current is very limited in a sustained line-to-ground fault, and overcurrent protective devices do not automatically trip. Hence, a characteristic shared by both of these systems is that a facility can continue to run through a ground fault. However, while impedance grounding has other advantages as discussed below, an ungrounded system is only recommended when it is critical that ground faults do not shut down a continuous process, such as in an industrial facility. Maintenance staff must be quick to clear these faults before they cause sustained overvoltage in associated phase conductors (which can cause insulation damage). For most CHP facilities (e.g., hospitals or campus environments), ungrounded systems are not recommended.

Grounding System Selection

The following is an overview of some of the design considerations which may impact the grounding system selection:

- *Voltage.* Proper generator grounding varies depending on the generator location in the facility system and the voltage at which the generator will be tied to the utility supply. Consider a typical situation—the utility service is medium voltage, the utility transformer has a secondary voltage of 4.16 kV, and the transformer has a low-impedance ground with a maximum ground fault current of approximately 200 A. The facility generator is also at 4.16 kV and is paralleled with the utility. In this scenario, the optimum configuration is for the CHP generator neutral conductor to have a high-impedance ground, which will limit the ground fault current to approximately 2 A. This fault current would be sufficient to activate effectively an alarm condition while still permitting continued operation until the faulted circuit is located and shutdown. In turn, this avoids a total system outage.
- *Harmonics.* Most generators manufactured today which are used in CHP systems are wye-connected. Since the third harmonic components of the phase currents are additive in the neutral, they can best be attenuated in the neutral. To accomplish this attenuation a grounding resistor helps perform this function. These grounding resistors are typically rated for a particular voltage and current and are provided within a separate enclosure. When harmonics are a critical issue for a facility, generator neutrals should be impedance grounded when paralleled with the utility service buses.
- *Mode of operation.* If the CHP generators are commonly not paralleled with the utility source, there are other considerations which must be taken into account for grounding purposes. First, if the distribution system feeds single phase loads, which is typical for nonindustrial facilities, its neutral must be solidly grounded so that it may be used as a circuit conductor, as required by NEC 230-95. Second, if the generator is paralleled with the utility and its neutral is high-impedance grounded, it cannot be used as a circuit conductor. To allow for both possibilities, a common solution is to provide a bypass device installed across the grounding resistor which shunts the impedance as necessary.

Bonding Requirements

As a separately derived system, a CHP generator must be grounded and bonded as per NEC Section 250.30. This section of the NEC has been revised most recently in 2008 due to the complexity and importance of grounding and bonding these types of complex and interrelated electrical systems. This section gives a summary of the components of a well-grounded system—the system bonding jumper, the grounding electrode conductor, and the grounding electrode. For more information, consult the NEC and perhaps one of the many books written on this topic to further explain the grounding section in detail.

Note that the summary below refers to a solidly or impedance grounded system. There is a separate section (250.30B) to cover ungrounded systems; however, since this type of grounding system is rare in CHP plants, it is not covered here.

A *system bonding jumper* is a connection between the grounding conductors of the CHP generator and the grounded (neutral) conductor in the main switchgear, and is a vital connection necessary so that ground fault current can return to the utility source. If a system bonding jumper is not in place, a fault would have to travel via the grounding electrode (i.e., earth), which is a very high-impedance path. If the impedance is too high, the fault current may be so low that it would trip a circuit breaker and create a potential (equipment and personnel) safety risk as well as an equipment damage risk that is unnoticeable and will go unchecked. The reader is to not be confused with an impedance grounding system as has been previously discussed above; the earth is at a much higher impedance path than any resistor used in an impedance grounding system. The size of the bonding jumper must be at least 12.5 percent of the equivalent area of the phase conductors. For services up to approximately 600 A, Table 250.66 of the NEC can be used as a shortcut to doing the calculation by hand.

The *grounding electrode* for a separately derived system shall be as near as possible to the grounding electrode for the main system. According to the NEC, the preferred grounding electrode to be used is either the metal water pipe or structural metal (both specified in NEC Section 250.52). The purpose of this grounding electrode connection is primarily to limit voltage imposed by lightning or surges, and to stabilize the voltage to earth during normal operation. It also provides a path to earth for static dissipation. Note that this electrode connection has virtually nothing to do with clearing faults because of the high-impedance path noted above.

The size and type of the *grounding electrode conductor* is dependent upon whether or not the CHP system has one generator (a single separately derived system, described in NEC Section 250.30-A3) or multiple separately derived systems. In both cases, the connection to the switchgear is the same point as where the system bonding jumper is installed, and shall be sized as per NEC Table 250.66. However, where more than one separately derived system is installed, a single grounding electrode conductor can be tapped with a listed connector to each of the separate systems. Since each of the grounding points for the separate systems are typically within the same room (and often within the same switchgear cabinets where a tiebreaker is used), this can save the cost of a large grounding electrode conductor being run potentially a long distance.

CHP Power Quality

The quality of the power delivered to a CHP facility is critical irrespective of the source. Voltage transients, surges, sags, etc. have always been part of an electrical system; however, with the technological advances in the types of facility loads over the years, the effects on system integrity caused by irregular voltage issues now more than ever have greater impact on the overall facility systems and equipment. While a comprehensive overview of power quality issues and solutions for these voltage irregularities and other issues is beyond the scope of this book, an additional discussion of harmonics and its relation to system grounding is important when thinking in terms of CHP systems and follows below.

As previously discussed, impedance grounding of the generator neutral limits the amount of fault current that will flow into the generator when a part winding ground and/or arcing fault occurs. One of the impacts generator impedance grounding will have is a likely minimized amount of damage to the generator. More importantly, though, this resistance significantly attenuates the third harmonic distortion from the generator and consequently to downstream electric loads.

Interestingly, generator stator windings are not truly connected in parallel with the axis of the generator shaft, but rather are set at an angle to the generator shaft. This approach is known as the generator pitch. Utility generators are usually $2/3$ pitch, which has been shown to produce minimum third-harmonic distortion in the generator output. However, generators used in typical industrial applications such as central plants are rarely $2/3$ pitch and therefore can produce a significant third-harmonic component of a magnitude that is related to and depends upon the pitch of the individual generator.

Careful attention to generator neutral grounding and winding pitch can produce outputs having a “clean” sine wave with very little harmonic distortion. As an example; if a 0.73 pitch generator was operated in parallel with a utility service wye-connected transformer, with both neutrals solidly grounded, the sine wave shape would most likely show objectionable third-harmonic distortion. However, if a $2/3$ -pitch generator was operated in parallel with a utility service wye-connected transformer with the transformer neutral solidly grounded and the generator neutral impedance grounded, the generator will produce a very good sine wave shape showing very little third-harmonic distortion. Since impedance grounded systems introduce other challenges, as noted earlier, the system designer must balance these challenges with reasonable expectations for harmonic distortion in the CHP facility.

Interconnection Rules and Standards

Perhaps the most critical reason that the electrical design for a CHP facility is different from other and more simplistic electrical design applications is due to the requirements for interconnection with the serving utility. Most electrical utilities will have rules and design/construction standards in place which regulate interconnections with the power grid. The rules and standards are in place to ensure that power distribution to the public is not compromised by smaller energy producers such as CHP facilities or alternative energy source providers like a photovoltaic array. For example, in the state of California, the California Public Utilities Commission (CPUC) has a specific rule (Rule 21) which all regulated public utilities must follow. Many of the smaller municipal utilities within the state have adopted similar rules, and it can be said that most state-regulated and municipal-run power utility providers in almost every jurisdiction will have some level of rules and requirements focusing on interconnectivity. These rules often include a very rigorous application and certification process which are discussed in general terms here. While a detailed description of this process is not included within this chapter, there are typically guidebooks or online information for the application process available from each local public utility commission and/or through each local utility.

Protection Requirement Considerations

When on-site generation and utility systems are operated in parallel, there are many factors such as point of connection, grounding, synchronization, protective relaying, and system isolation that must be considered to provide safe and efficient operation. All of these functions in one way or another fall under the loose but very important term of “protection.” Without system protection on the electrical systems, both the utility and CHP systems and its downstream loads are subject to unsafe operation and potentially very harmful situations.

In general terms, the electric grid can be divided into two distinct sections. The first section is the transmission system, which is the backbone of the national electric

distribution system. The transmission system operates at high voltages (typically 110 kV and above) and, in the United States, is federally regulated. The second section is the local distribution system, which is the medium voltage system that commonly provides energy more directly to the customers. This local distribution system is the one which is typically regulated by public utility commissions and this is the one which is interconnected with CHP systems. For that reason, this discussion revolves around the distribution system. The reader is encouraged to further review transmission systems as they are not discussed in further detail within this book.

There are two typical types of distribution system, each with their own particular protection requirements. The most common distribution system type is called the *radial system*. In broad terms, the radial system is similar in concept to a wheel with spokes. In this configuration, the utility substation is the center of the wheel while the spokes are the feeders which carry power to the customers. Typically, these feeders are expected to carry energy in only one direction—from the utility to the customers—and they are not joined downstream from the substation. Therefore, the distribution system likely was designed by the utility assuming unidirectional power flow and not for power flow from a CHP facility back to the substation. With the increased importance of CHP systems and their applications today, both customers and utilities have had to review ways in which to allow for bidirectional power over these initially designed and installed radial systems. Such protection system opportunities are discussed in greater detail below.

The other type of distribution system is called a *network system*, and is more common in higher and more densely populated areas, which as expected have higher load requirements. In this system type, there are multiple feeders originating in a substation (much the same as with a radial system), but instead of single unidirectional flow, they are joined together downstream from the substation in a variety of configurations. This method of “loop feeding” via a network system improves reliability for utility customers because it provides them with a secondary feeder in the event the primary feeder is compromised. By definition, this network distribution allows for simple bidirectional power flow and the distribution system design includes network protectors to protect the local distribution system. Typical network protectors have relays, which are not intended to be frequently operated, so protection relays on switchgear must act quickly to isolate faults and to allow problems to be corrected before network protectors are opened and reset.

Another factor which has impact on specific protection requirements is the agreement for power export between the CHP facility and their serving utility. An agreement like this is often dependent on the type and size of the CHP facility. For a small facility with a prime mover like a fuel cell or microturbine, the most likely agreement is for nonexport. In this case, the energy generated by the CHP facility is not expected to feed into the utility distribution system since the generating capacity of the CHP generator is only a small percentage of the overall facility load. For example, in California, if the CHP generator capacity is no more than 25 percent of the rating of the facility’s service equipment, the protections requirements of this type of system usually dictate one of two probable solutions for use.

One solution is the use of a power monitor on the incoming utility power. The utility will determine a set point for expected load based upon a percentage of typical demand loads. If the load for the facility drops below the designated set point, the CHP control system will be required to reduce its generation capacity or drop generation

completely until the load increases to a high enough level (above the set point). Another protection possibility is a reverse power relay, which by function in this application detects power flows from the CHP facility to the utility distribution system. If the power flow occurs for too long a duration (typical setting is 2 seconds), or the amount of power being generated is too high (perhaps 0.2 percent of the utility transformer rating), the CHP controls again will respond by reducing or dropping power generation.

This reverse power relay solution is more common when the CHP facility and utility have an agreement allowing for incidental power export as it is more likely that there will be power flowing back onto the utility distribution grid in this mode. When this type of plant is designed, the generator is often sized with capacity reasonably close to the actual facility load. However, the agreement between the facility and utility is typically such that there is no compensation back to the facility when it generates power that feeds back into the utility. Therefore, there is no advantage to the facility to generate more power than it needs (hence the term, "incidental" export).

The advantage for a facility negotiating this type of power export agreement is that it does not have to respond as quickly to a reverse power situation as it does when it agrees not to export any power at all. A facility that has frequent sudden reductions in power load (e.g., large electric power-driven chillers suddenly stopped, or an industrial facility with extremely large motors turned off) may not want to quickly cut generator power because this may affect other outputs from the CHP plant. A slow reduction in generation to respond to more than temporary reductions in facility load has the advantage of allowing a smoother transition combined with as little wasted generation (i.e., noncompensated energy flowing back to the utility) as possible.

One step beyond this type of agreement is one in which the facility has a net energy metering system. If a facility has a large load diversity, perhaps on a weekly basis where the load is much less on weekends, or on a yearly basis when summer and winter loads are quite different, it may wish to maintain a constant generation capacity without regard to whether or not the CHP plant is producing slightly more or slightly less than the facility electric load. In this situation, the utility will track the energy it provides the facility when it is an importer and the energy it gets from the facility when it is an exporter. The net difference gets reconciled in energy usage costs either monthly or yearly. Note that this type of agreement is in general a recent development, partially born from the recent propagation of alternative energy source exploration and implementation, the most notable being the solar power generation industry. It is important that the CHP facility designer investigate whether this opportunity exists with their local utility before adding the metering and relaying necessary for net energy metering.

Protective Relays

The major component in utility protection is relays specifically designed for their purpose. Relaying must provide for safety and proper sequence of operation, and must also protect the utility system and personnel from harm. It is recommended that protective relays used in CHP systems should be an electronic digital type. Packaged relaying systems readily available from many companies provide a self-contained single-component package that can be ordered with any (practically any) combination of protective relaying requirements. These packaged relaying systems are very reliable, have infinite repeatability, are compact in size, and do not require recalibration. Simple programming can turn on or off functions as needed to customize the relay system to a

particular facility's needs. One potential problem with packaged relays is that the entire relaying system is a single point of failure. Fortunately, however, packaged relay failure is rare.

While the older style induction-disk relays are also still an option, they are becoming more and more obsolete. While these induction-disk types have an excellent history, they do have some inherent disadvantages as compared to the electronic type. The rotating disk has inertia and must rotate to its original position to reset after pickup, resulting in substantial reset time. In contrast, the electronic digital relays can reset instantaneously, providing immediate repeatability of operation. In addition, since electronic digital relays are nonmechanical they have no springs to adjust or calibrate.

Another consideration in the design of a CHP protection system is whenever generators must energize transformers, then the overcurrent, differential, and current-balance relays, along with the integral trip units of low-voltage breakers, must be carefully selected and set. The relays will need to withstand the high magnetizing inrush currents required for transformers without tripping, yet provide proper protection to the energized transformer. This is one more reason to look carefully at electronic digital relays.

Specific Protection Requirements

As noted earlier, the protective functions required by a utility are not to protect the CHP generating facility, but rather to protect the utility distribution system. There are a number of protective functions that are typically required by all utilities for all interconnected generating facilities. For example, all interconnections will require over/under voltage trip and over/under frequency trip, which ensures that the voltage and frequency of the two sources are in synchronization while connected.

The CHP generators must be separated from the utility service grid immediately upon the occurrence of a power system disruption or disturbance that could result in an unsafe, undesirable or objectionable operation. Typically, the fastest reestablishment of a utility service, taking into account the operating time of the utility relaying and reclosers, is approximately 12 cycles. When the utility service is returned, there is no assurance that it will be synchronized with the CHP system, so the protection system must ensure that there would be no possible chance that the two sources will still be connected at the time the utility service is restored. Therefore, the CHP generator system must be disconnected from the utility, via the protective relaying system, within a maximum of 8 to 9 cycles. Once disconnected, the generators may provide emergency and standby power, with load-shedding as necessary to stay within generator capacity. When the utility service returns and is stable, then the generators could once again be paralleled with the utility grid. To accomplish this, it is imperative that a protective relaying and control system scheme be designed to perform these necessary functions automatically in a logical, safe, and sequential manner. For system test, maintenance, and recalibration, certain manual controls may also need to be incorporated, such as a manual synchronizer. These should be limited to keep everything less complicated, but must be configured and interlocked to prevent and prohibit any sequence of operation or combination of connections that could result in an unsafe and undesirable operation.

Therefore, a typical protective function required is voltage and frequency sensing, with time delay. This will ensure that a CHP generating facility currently disconnected from the utility does not reconnect with the distribution system unless its voltage and frequency are within a set range, and have been in that set range for a certain period of

time. This is known as a synchronization relay. Often the utility will require the synchronization time is 30 seconds or more before the generator can reconnect after a utility disturbance. This will allow the utility system (reclosers, sectionalizers) to reset to their normal operating state. Sectionalizers often will not reset and operate correctly without a long enough loss of voltage.

The other CHP system condition that a utility is typically very concerned with is a condition known as “islanding.” In this condition, the CHP generator is still providing energy to the facility when the utility has lost power. For a large facility where the CHP generator capacity is quite a bit smaller than the facility load, this is not necessarily a problem, provided maintenance workers at the facility understand their facility still is partially energized and account for this. However, if the CHP generator is also exporting power into the utility distribution system, it is creating an energized “island” for the utility, surrounded by nonenergized distribution. This is a potentially dangerous situation for utility maintenance workers.

The utility will want assurances that the CHP facility design has protection against islanding. There are a number of ways of providing this protective function, including passive methods like voltage relays (undervoltage, ANSI #27 and overvoltage, ANSI #59) or frequency relays (ANSI #81). However, while it is expected the generating facility voltage or frequency will drop slightly whenever the utility connection is no longer present; however it isn't an absolute guarantee. Active protection methods may include measurement of the response to a small disturbance added into the system by the CHP facility. If the utility is connected, the system impedance will be much smaller (near zero) than the impedance of the CHP facility in a stand-alone situation, and the impact of the disturbance will change significantly when utility is disconnected.

There are other system protection and coordination issues which are dependent upon the generator size, utility connection type, and grounding type. For example, improper protective device coordination can be a concern, particularly when it leads to nuisance fuse blowing (which can turn a temporary fault into a permanent outage). Voltage issues within a CHP facility may cause utility sectionalizers to operate incorrectly, or contribute to a voltage regulation problem. Solving these potential issues requires project-specific relaying solutions on a case-by-case basis. The final section of this chapter includes a sample riser diagram with typical relays and discusses how these relays help solve some typical issues.

Regardless of how or where the on-site generators are connected into the system, safety must always be a first consideration for both personnel and equipment, and must include positive means of locking out either the utility or the CHP system in order to provide safe access to the circuits by facilities and maintenance personnel. Therefore, padlocking provisions on the tie-point disconnect which are made accessible to the utility company personnel is an absolute essential safety requirement. Most of the utility companies will also require a ground and test device for medium-voltage switchgear to assure that it is grounded before anyone attempts to service the equipment.

Interconnection Process Overview

The process which the electrical systems designer must follow to meet utility rules for interconnection will vary by locale. However, there are some standards that apply to any facility design regardless of utility and jurisdiction. An integral part of the application process is providing a drawing package consisting of an electrical single-line drawing, equipment layout plans, grounding plans, site plan, and protective relaying specifications. Of course, the power and controls single-line drawings are the heart of this documentation

package and are meant to give utility engineers a general understanding of the proposed interconnection. The interconnection documents will need to show the CHP generator, switchgear, utility feeders, conduit/conductor specifications, and control relays; typically, the utility will want to see the same information that a contractor bidding the job would need to construct the electrical installation correctly.

Depending on the interconnection agreement, the utility will also want to see specifications for some of the electrical equipment. For example, when an automatic transfer switch (ATS) is used, perhaps when the plant is used in a standby application, the utility will want details on the transfer mechanism. If it is a closed transition ATS, where both the utility and CHP generator are connected at the same time for a moment, the utility will need to see specifications detailing the synchronization and protection schemes between the two feeders. In a similar way, the utility will wish to see details on transformers (such as impedances) and switchgear.

Another critical piece of information is a description of the CHP generating equipment. The interconnection application will indicate the number (and prime mover type) of generators being installed and model numbers. It will also ask for electrical information such as

- *Nameplate ratings (both kVA and kW).* Often, the utility will want the gross and net ratings, with net defined as the difference between gross rating and auxiliary loads used to operate the generator. There may be a significant difference in these values.
- *Operating voltage and wiring configuration (single phase or three phase).*
- *Power factor rating (with adjustment range).*
- *Grounding system used (solidly grounded or impedance grounded).*
- *Short-circuit current produced by the generator.* This is critical, and can be calculated based on synchronous, transient and subtransient reactance (for a synchronous generator) or locked rotor current (for induction generator).

Once the electrical designer has provided the utility with all the initial information required, the application undergoes an initial review. In this stage, the utility reviews the design with an eye to the interconnection agreement (nonexport, incidental export, net metering). The certification of the equipment is reviewed. Voltage drop and short-circuit current calculations are tested. During this time, an open line of communication between the designer and utility is critical to ensure a smooth review process. If the CHP generator is relatively small and the utility is satisfied with all of the design parameters, this may be the end of the review and the application would be approved.

However, there may be a further review required where the generator capacity is a greater percentage of the facility load or the interconnection is more complex (such as in a network system). The utility will do their own interconnection study, the cost of which is usually borne by the CHP facility owner. It is critical that the time and cost for this study is built into the project schedule and design budget. If it is not, then the economic models used to justify the CHP facility in the first place may not be accurate.

Final Interconnection Acceptance and Start-Up

Of course, once a design has been approved and installation of the CHP generating facility is underway, it is critical that the installation follows the approved design drawings

and equipment specifications. The utility will likely monitor the installation process and if the design or equipment selection varies from approved conditions it may trigger another utility (and often regulatory agency) review and approval process. As one can imagine, this has impacts to schedule and budget. Another potential schedule impact is the pretesting which requires temporary (and extensive) paralleling between the CHP generator and the utility. Special agreements will likely be necessary and the time taken to reach these agreements must be accounted for.

There are two separate stages to the construction process which ensures a successful switchgear installation in a CHP facility—equipment certification and commissioning. Although it may be a requirement that certification occurs at a third-party independent facility, equipment certification is most often done at the switchgear manufacturing facility. Just as there are multiple components in a piece of switchgear, there are multiple types of certification. One possibility is that each of the components has been certified, and then all of the components are combined and tested as an assembly. In this case, the switchgear is certified when it leaves the factory as a complete system, and the CHP design engineer and facility owner can trust necessary settings have been confirmed.

Another type of certification entails testing all of the components and evaluating that each of them performs its particular function. Then, the components are assembled as per a previously tested protocol which has proven the components will work together. In this case, however, it will be more critical that the connections and settings are tested and verified in the field. This testing is a major part of the commissioning process. With either method, the switchgear used in a CHP installation will almost certainly require special certification by a nationally recognized testing laboratory (NRTL) for interconnection with the utility.

Commissioning testing will be the final step in the installation process to assure the facility owner that the switchgear will operate as the CHP electrical design engineer has intended. Of course, during the installation it is to be expected that qualified experienced CHP system contractors run interim tests after each stage of the installation, in order to catch and correct issues long before construction is complete. However, a final testing program will need to be specified which satisfies the owner and the utility that the switchgear works as intended, under both normal conditions and fault conditions. This testing program must be specific enough to note specific components to be tested in each step. For example, the commissioning specification might note a specific relay or disconnect which will have to operate to ensure an overvoltage condition on a particular downstream feeder does not propagate to other feeders; that over voltage condition would be simulated as part of the commissioning process.

Sample System Diagram

There are many possible connection configurations when CHP facilities interconnect with a utility. These are dependent on the type of CHP generator, the size of the CHP facility, the particular requirements of the serving utility and the type of utility distribution system. What follows, for reference, is one typical example of the protection between utility and CHP facility, and the additional protections typical for engine-driven generators.

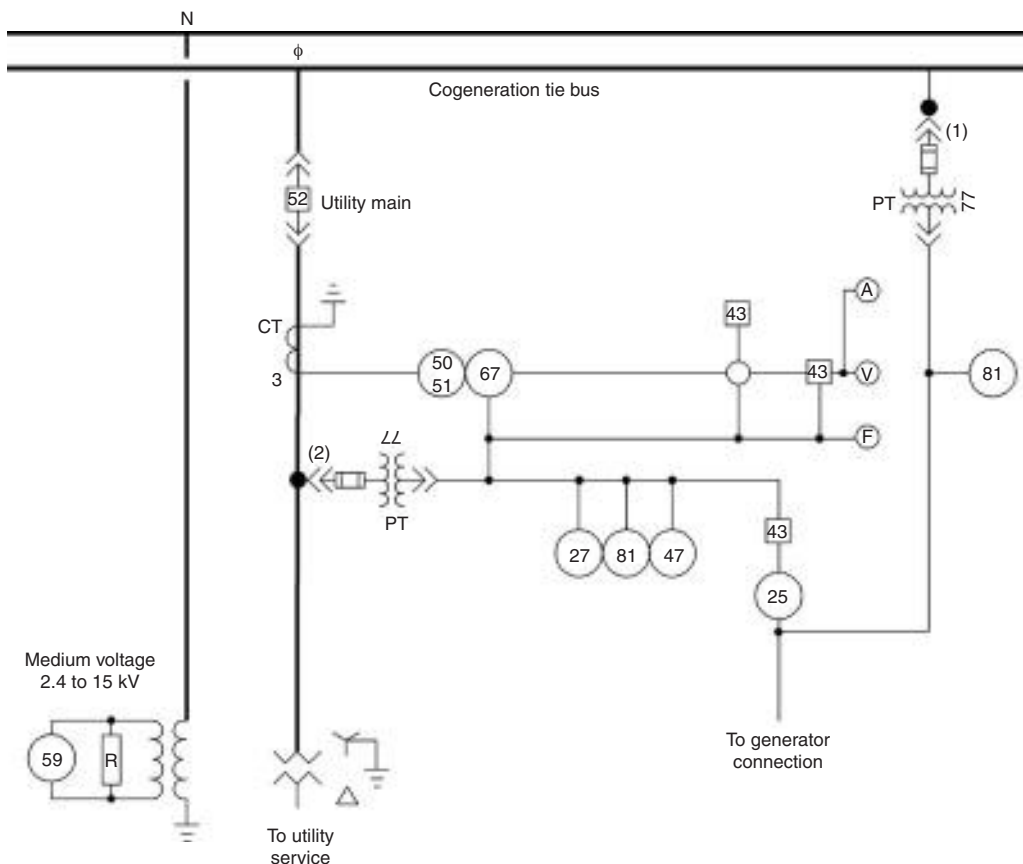


FIGURE 11-1 Typical protection for CHP generator connected to utility–utility section.

A typical relaying scheme for connection of the utility and CHP facility generator to a common tie bus is shown in Figs. 11-1 and 11-2. The devices shown are IEEE/ANSI Standard Device Numbers and their function is described below.

25-Synchronizing check device. Electronic control causes all online CHP engine-generator sets to be matched in frequency, voltage, and phase angle to the utility service before the utility connection circuit breaker (ANSI device #52) can be closed. Differences between the utility and generator bus must be minimized at the instant of paralleling to prevent transient mechanical torque impulses on the engine generators and to limit electrical disturbances on the bus. Typical tolerance limits that permit control stability would be within a 0.2 Hz frequency deviation or less; a voltage deviation of 10 percent of normal voltage or less; and a 5° or less phase angle deviation.

27-Undervoltage relay. This is a three-phase relay which detects an abnormal low voltage at the point of common coupling with the utility connection. It is designed to separate the two systems on undervoltage and also prevents closing of the utility service circuit. The relay prevents synchronizing and paralleling of the CHP bus with

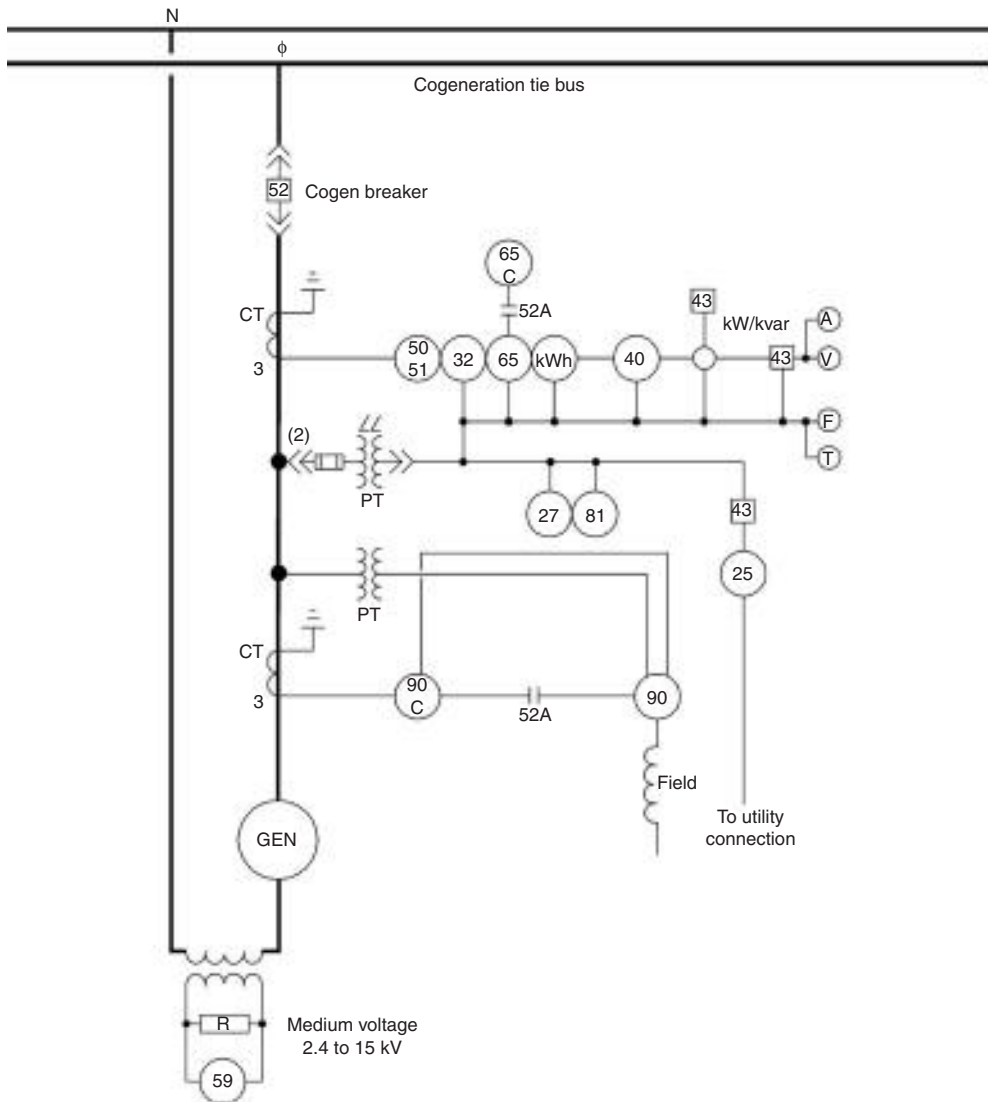


FIGURE 11-2 Typical protection for CHP generator connected to utility-generator section.

the utility if utility voltage is below nominal, and helps detect issues of islanding, voltage regulation malfunction, or faults causing voltage dip. Because system voltage transients are normal, this relay usually has a 2-second time delay on drop out and a 1-second time delay on pick up. Drop out is typically at 75 to 80 percent and pick up at 90 percent of nominal voltage.

43-Manual selector switch. These are not part of the control system, but rather allow for multiple meter readings and are often incorporated directly into digital meters. Three manual selector switches are shown in this example: one selects phase for

ammeter and voltmeter; one selects phase for synchronizer; and one selects kilowatt or kilovar reading for meter.

47-Phase-sequence voltage relay. This is a very high-speed relay that separates the two power sources on undervoltage and excessive voltage unbalance. It prevents resynchronizing of the generators with the utility until the utility is at normal voltage on all phases and has the proper phase sequence.

50/51-Instantaneous and time-delay overcurrent relay. These are for three-phase protection and disconnection on overcurrent and fault-current flow in either direction. Curves and settings are selected to provide coordination with other protective elements in the system and to ensure rapid isolation of the CHP bus from the utility upon occurrence of a problem not handled by other protective devices.

52-AC breaker. This is to open or close the circuit automatically as directed by the relays, or manually if necessary.

59-Overvoltage relay. Senses ground fault in the medium-voltage impedance grounded system (with delta primary) and opens the device 52 AC breaker.

67-Directional overcurrent relay. A very high-speed (within three cycles), three-phase relay with a primary function of separating the CHP bus from the utility service grid whenever the instantaneous current flow into the utility system from the generators exceeds the full-load current of the CHP power system. This prevents a fault in, or loss of, the utility system from taking more power from the CHP system than it can safely deliver. After the separation, the protective relaying of the utility and CHP systems will determine the location and type of malfunction and respond in the proper manner. The fastest a utility system can reclose is about 12 cycles; this high-speed relay operation plus the operating time of the circuit breaker should separate the two systems in less than nine cycles.

81-Frequency relay. This is also a very high-speed relay that separates the utility and generator sources whenever the bus frequency drops to less than 59.5 Hz (60-Hz system). The engine governor will vary the speed of the engine to match the bus frequency, which is determined by the utility system frequency.

The functions of utility connection relays, device functions 52, 50/51, 27, 81, 25, 59, and 43, are for specific protection at the utility and CHP interface bus. In addition, the following relaying devices are specifically required for the engine-driven generators, and their functions are as follows:

32-Directional power relay. This device senses the direction of power flow in the generator circuit. In this application it is usually referred to as a *reverse power relay*. Reverse power is power flow into the generator which occurs when the prime mover loses its driving force. Power into the generator drives it as a motor, which then rotates the engine. Under these conditions, the generator must be disconnected and shut down. Since circulating or synchronizing power flow will always occur upon initial connection of the generator to the bus, some time is required to permit the generator control system to cause the generator to provide a forward power flow. Therefore, this relay must have a time-delay function. The trip point of the relay must be set to ignore synchronizing power, but respond to the lowest reverse power flow and duration that indicates a motorizing unit. This trip point should be set at 2 seconds at reverse power of about 8 percent of the forward power rating for diesel and natural gas

reciprocating engines, and about 2 percent reverse power for combustion turbines. As the trip points are a point in time and a point in power setting using an inverse time characteristic for this relay is neither appropriate nor desirable.

40-Field relay. When this relay senses loss of field excitation, it will disconnect the generator set from the bus and shut it down. This device should look into the generator, using the AC current and voltage relationships to determine a loss of excitation.

Summary

The electrical systems design for a CHP facility should be one that is configured to allow for maximum flexibility and optimization of energy supply to the facility. In doing so, the electrical design must take into account the complex requirements and regulations that govern the interconnection of the CHP facility and serving utility, and must provide the necessary protection, controls, and switchgear to protect the utility, switchgear, equipment, and personnel. Most importantly, the electrical system designer must work closely with the rest of the CHP design team and the facility owner to ensure this complex system is well coordinated and provides value to the owner.

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Obtaining a Construction Permit

Karl Lany

Construction and, therefore, design of a new CHP facility is typically dependent upon the ability to obtain permits from a variety of regulatory agencies. Municipal planning departments and commissions may have authority to review project plans and specifications to determine consistency with land use ordinances and land use plans, and project approval may require holding public hearings. Project plans may also be subject to a review by local government agencies to determine consistency with building codes as well as health and safety codes. Environmental agencies that enforce air quality, water quality, and public health regulations often operate independently of municipal governments and have permitting authority over CHP projects.

Environmental Assessments and the Permitting Process

In regions of the world with mature environmental regulations, the process of issuing a construction permit often includes consideration of a wide range of environmental impacts. The environmental assessment process is becoming even more common as an increasing number of communities grapple with global warming, deteriorating air and water quality, increased noise and exposure to hazardous compounds. Even in cases where government authorities do not issue permits or require an assessment of environmental impacts, project developers may be faced with the challenge of demonstrating (to funding organizations) that proposed projects result in acceptable environmental consequences.

For instance, the United Nations Development Program has adopted environmental assessment protocol and performance standards for many projects in order to qualify for funding through the organization. The United States Agency for International Development (USAID) also conducts cross-media environmental assessments for foreign projects that are funded by the agency. Environmental assessments for foreign projects that are funded by USAID are similar to the assessments that are conducted for domestic projects. USAID also applies minimum environmental standards for foreign projects that are similar to the environmental standards that would be applied to domestic projects. Many

multinational corporations also implement environmental performance standards for any project undertaken by the organization, even if a local government agency does not consider environmental impacts or establish standards for a project.

Issuance of a permit or qualification for funding is likely to depend upon the review of an application package. This chapter offers guidance on drafting an application package that adequately discusses the types of environmental impacts that are typical of most CHP projects, including degradation of air quality (including global warming), excess noise, and the risks associated with the transport and storage of hazardous materials. Project size and location can also lead to concerns about impacts not only from CHP operation, but also from the construction of the CHP facility. This chapter also provides an overview of the manner in which environmental impacts are typically managed or regulated by local, provincial (state), and national governments. By understanding the concerns of environmental regulators, the project owner, project engineer, and/or developer can more effectively navigate the application process. This will help ensure timely issuance of necessary construction permits, and in some cases, secure project funding.

Building an Effective Application

The process of obtaining environmental permits or the authorization to construct a CHP system can be time consuming. Prior to approving an application and authorizing construction of a CHP system, the permitting agency will have to answer the following questions:

- Will the project violate any existing laws, ordinances, or regulations?
- Will the project result in unacceptable environmental impacts?
- Will the project result in unacceptable hazards or health risk?
- Will the project create a nuisance to local communities?
- Are adequate steps proposed to mitigate adverse project impacts?

If the goal is to quickly obtain authorization to construct a CHP system, then the project developer must take steps to ensure that the permitting authority has the necessary information to easily answer these questions. Preparing an effective application package will help the permitting authority better understand the project and to issue permits that are structured to ensure operating flexibility. Such a package must also be structured in a way that allows for efficient processing by the permitting authority. It should include official forms accompanied by a report containing an adequate assessment of pertinent environmental impacts. Generally, an application report should provide an overview of existing environmental conditions, summarize the proposed project, review applicable regulations, quantify environmental impacts, demonstrate compliance with applicable regulations, and may include suggested permit language. Each of these components of the application package is summarized in this chapter.

Overview of Existing Conditions

The project engineer or developer should identify the conditions surrounding the proposed project. This includes area land-use characteristics and an overview of the potential receptors who live and work near the proposed project. The application should

also include detailed information about the host facility (location, size, existing emission sources, etc.) and an overview of the background or existing environmental conditions. For example, if discussing air quality impacts one should provide an overview of air quality in the region surrounding the facility. The assessment of existing conditions should be as objective as possible and should rely upon measured and quantified conditions, relative to official standards.

Project Proposal

The application package should contain a clear and detailed discussion of the proposed project. Key considerations include the proposed equipment, operating schedules, fuel consumption rates, and operator background information. The proposal should be supplemented with facility plans and diagrams, process flowcharts, and manufacturer's equipment specifications. If the CHP system is replacing existing equipment at the facility, an overview of that existing equipment should also be included in the proposal.

Applicable Environmental Standards and Regulations

The project engineer or developer should summarize laws, ordinances, and regulations affecting the project. Such regulations typically specify minimal technology standards, impact thresholds and limits, operating practices, and conditions for selecting an appropriate project location. Applicable regulations may be written, implemented, and enforced by local, regional, and/or federal agencies.

Project Impacts

The project engineer or developer should quantify and assess the project's environmental impacts using established protocols. Impacts should reflect the facility's typical and potential maximum operations. If the project includes the replacement of existing equipment and operations at the host facility, the impacts of those operations should be assessed. If appropriate, the impacts of those operations should be netted against those of the proposed CHP project. Often, the project engineer or developer will incorporate specific technologies, operating schedules and other mitigating measures that will lessen the environmental impacts of the project. When quantifying the project's impacts, it is prudent to reflect both the baseline project impacts, as well as the final impacts considering any mitigating measures that will be incorporated.

Determination of Regulatory Compliance and Proposed Permit Conditions

Once the project engineer or developer has quantified the project's environmental impacts, he should then summarize how the project complies with the identified applicable laws and regulations. Ensuring compliance with regulations will often necessitate that the resulting construction permit stipulate operating conditions. It is prudent for the project engineer or developer to identify necessary permit conditions and suggest permit language that ensures compliance in a manner that also promotes operating efficiency and flexibility.

Air Quality

By far, potential air quality impacts pose the greatest environmental concern attributed to the development of most CHP systems. Combusting fossil fuels and biogases in CHP systems results in emissions of criteria pollutants such as nitrogen oxides (NO_x) and

reactive organic gases (ROG) that lead to the formation of ambient ozone that can affect public health, biological resources, and property. CHP systems also emit sulfur oxide (SO_x), carbon monoxide (CO), and microscopic particulate matter (PM) that lead to health impacts, property damage, and regional haze. The operation of CHP systems also releases hazardous air pollutants such as acrolein, xylenes, and aldehydes and are known to increase the risk of cancer in addition to chronic and acute health risks in humans. Finally, CHP systems emit large amounts of greenhouse gases such as carbon dioxide (CO_2) and uncombusted methane (CH_4) that are believed to contribute to global warming. As noted in previous chapters, CHP still has an environmental benefit due to the high overall system efficiencies and the reduction of fuel combustion for thermal requirements. Table 12-1 includes a summary of pollutants that are typically emitted from combustion-based CHP systems.

The permit application for a CHP system should quantify the air pollutants resulting from the proposed project and also assess their potential impacts on the environment and health. It should also assess how regulations apply to the project and how the project will comply with those regulations. This section provides additional details of the types of regulations affecting air quality impacts that may apply to CHP projects. This chapter attempts only to provide a general regulatory framework that the project engineer or developer may expect to encounter, regardless of the facility location. The specific air quality regulations that may apply to any single project cannot be effectively addressed within a single chapter.

Technology and Emission Standards

In almost any instance, the engineer or developer will have to demonstrate that the proposed project meets minimum technology and emission standards. Generally, these environmental performance standards reflect reasonably available and current technology. In the case of lean burn reciprocating internal combustion engines, environmental performance standards typically reflect the use of modern engine technology, but do not necessarily require post-combustion emission control devices. For example, the United States Code of Federal Regulations specifies standards, known as *New Source Performance Standards* (NSPS) for reciprocating internal combustion engines. For natural gas-fired reciprocating internal combustion engines, NSPS presently specify that the engine must be a lean burn engine that can meet 1.0 to 2.0 g/bhp-h NO_x , 2.0 to 4.0 g/bhp-h CO and 0.7 to 1.0 g/bhp-h VOC (bhp-h is brake horsepower-hour). Although modern engine technology is needed to meet these standards for lean burn engines, the NSPS are lenient enough to allow operation without selective catalytic reduction systems (SCR) or oxidization catalysts. Rich burn engines have higher uncontrolled emission rates, but their emissions can be controlled with relatively low-cost three-way catalyst technology. The NSPS for rich burn engines incorporate the low-cost control technology. For prime power diesel fueled engines, NSPS requires the use of SCR systems or oxidization catalysts, only if engine manufacturers are also required to integrate the emission control technologies into the base engine packages. The integration of emission control technology into new diesel engine packages are scheduled to be implemented in the years 2009 through 2014.

Minimum standards also exist for combustion turbines. As with lean burn reciprocating internal combustion engines, the minimum standards typically mandate the use of current engine technology, but do not necessarily mandate the use of post-combustion

Pollutant	Impacts
Nitrogen oxides (NO _x)	Includes various nitrogen compounds such as nitrogen dioxide (NO ₂), nitric oxide (NO), and nitrous oxide (N ₂ O). NO _x leads to the formation of atmospheric particulate matter, ground-level ozone (smog), and acid rain. NO ₂ exposure can lead to, or aggravate, respiratory ailments. N ₂ O is a greenhouse gas
Reactive organic gases (ROG)	Precursor pollutants that lead the creation of atmospheric particulate matter and ground-level ozone (smog). Many organic gases are hazardous compounds that can lead to increased cancer and other health risks
Carbon monoxide (CO)	Can temporarily or permanently impact the human brain, nervous tissues, heart muscles, and other tissues that require a large amount of oxygen to function
Sulfur oxides (SO _x)	Irritates nerves in the lining of the nose and throat and lung. This can cause reflex cough, irritation, and may lead to narrowing of the airways. Persons suffering from asthma and chronic lung disease are most susceptible. SO ₂ emissions contribute to acid rain, acid fog and atmospheric PM
Particulate matter (PM)	Fine particles can be aerosol carriers of toxic and biological materials that are easily inhaled and absorbed into the bloodstream. Exposure to PM can lead to increased cancer and other health risks. PM is a major cause of visibility impairment (regional haze). PM from diesel combustion is considered to be a carcinogen
Methane (CH ₄)	Greenhouse gas
Carbon dioxide (CO ₂)	Greenhouse gas
Acetaldehyde	Increased cancer and chronic health risks
Acrolein	Increased chronic and acute health risks
Ammonia	Increased chronic and acute health risks
Benzene	Increased cancer, chronic, and acute health risks
Butadiene (1,3)	Increased cancer and chronic health risks
Ethylbenzene	Increased chronic health risk
Formaldehyde	Increased cancer, chronic, and acute health risks
Polycyclic aromatic hydrocarbons (PAH)	Increased cancer risk
Napthalene	Increased cancer and chronic health risks
Propylene oxide	Increased cancer, chronic, and acute health risks
Toluene	Increased chronic and acute health risks
Xylenes	Increased chronic and acute health risks

Source: South Coast Air Quality Management District, Diamond Bar, CA.

TABLE 12-1 CHP Pollutants and Impacts

emission control systems. Environment Canada, the Canadian equivalent of U.S. EPA, issued NO_x guidelines for stationary turbines that allow credit for heat recovery and generally reflect the use of reasonable technology, without the use of post-combustion emission control devices. The United Kingdom, Australia, Germany, and many other national governments enforce minimum emission standards for gas turbines that can be met without the use of post-combustion emissions control technology. The U.S. NSPS for stationary gas turbines also allows one to waive the use of post-combustion emission controls. Year 2006 amendments to NSPS for power generating gas turbines rated at 3 to 50 MW include a NO_x standard of 42 ppmv (parts per million by volume) at 15 percent O_2 or 2.3 lb/MW-h.

Other national and international organizations also specify minimum standards for reciprocating internal combustion engines to qualify for funding opportunities. USAID funds and oversees many projects in developing countries and requires that reciprocating internal combustion engines meet the minimum NSPS standards that would apply to projects located in the United States. The United Nations and the World Bank also place minimum emission and performance standards on various projects that they sponsor.

The technology standards outlined above are only minimum standards. In many cases, local permitting agencies may require that more stringent technology or emission standards be met due to regional environmental conditions or project-specific circumstances. For example, while U.S. NSPS provides for the installation of a natural gas lean burn engine or a natural gas turbine with no additional emissions controls, local permitting agencies may require the installation of an SCR system to control NO_x emissions by 90 percent and an oxidization catalyst to control ROG and CO emissions by 50 to 85 percent. Even the U.S. EPA requires much more stringent standards known as best available control technology (BACT) or lowest achievable emission rate (LAER) for certain large facilities and for projects in areas that do not meet national ambient air quality standards.

The concept of tailoring more stringent standards to meet local environmental challenges is not unique to the United States. Even though Environment Canada offers gas turbine installation guidelines, local provinces also regulate the installation of gas turbines. The Province of Alberta requires that new natural gas-fired turbines rated below 20 MW meet a NO_x limit of 0.6 g/MW-h. These standards reflect newer engine technology than is suggested in national guidelines, but can still be met without the use of post-combustion emission controls. The Alberta standards are applied to a project located in the province, regardless of the guidelines that are issued by Environment Canada.

Technology Assessment Tools and Methods

Because technology changes rapidly, it is not feasible to publish and identify current local requirements that may apply in all situations. While minimum technology or emission standards tend to be specified in fairly static regulations or policy statements, more stringent standards that may be enforced as BACT or LAER, or that may otherwise be mandated by permitting agencies, tend to be less static and therefore cannot easily be specified in formal regulations. When initiating discussions with local permitting agencies, the project engineer or developer should inquire about all emission and technology standards that may be mandated by the agency or by other local environmental agencies.

Local permitting standards are typically specified in policy or guidance documents that the permitting agency may issue. This is especially true when the agency encounters multiple applications for similar projects. In cases where the permitting authority requires the use of BACT, but does not have significant experience with CHP systems, the applicant may be required to take on the burden of demonstrating that the proposed technology is appropriate for the project. In these cases there are various resources and tools that are available to the applicant to assist in the equipment selection process such as technology clearinghouses, vendor technical data, and technology analysis tools and models.

Technology Clearinghouses

Several environmental agencies maintain clearinghouses and technology guidelines that a project engineer or developer may find useful, even if the proposed project is not within the jurisdiction of those agencies. The U.S. EPA manages BACT/LAER clearinghouse into which local permitting agencies submit information about recent projects. Through this clearinghouse one can see what various agencies perceive to be achievable emission rates for a variety of applications, including CHP. U.S. EPA maintains this clearinghouse on its Web site www.epa.gov. The California Air pollution Control Officers Association maintains a similar clearinghouse that contains recent permitting data from the 34 local air districts within the state (www.arb.ca.gov).

Some agencies offer technology guidance documents. The South Coast Air Quality Management District, which regulates air emissions in Los Angeles, California, maintains a BACT guidance document that reflects periodic evaluations of current technology. Private and public sector representatives participate in the guidance development process through the review and debate of technological advancements in the United States and elsewhere. The broad-based participation by technology manufacturers, project engineer or developers, and system operators and regulators helps to ensure that the resulting technology guidance is assertive, and also that the resulting standards are achievable (www.aqmd.gov).

Vendor Technology Data

Vendor specification sheets, emission guarantees, and price data are also useful in identifying the appropriate technology and emissions standards to be applied to a CHP project. Specification sheets can show differences in the performance of various emission control options that may be applied to the base combustion technology. It is important to note that the lack of a vendor emissions guarantee (or a vendor emissions guarantee at levels that are higher than what is typically achievable) will not necessarily justify the application of less stringent emissions or technology standards than the permitting agency would otherwise apply to a CHP project.

Technology Analysis Tools and Models

The combination of specification sheets and price data will help both the applicant and the permitting agency understand the cost-effectiveness of optional technology that could be utilized for a CHP project. In many cases, but not all cases, the cost-effectiveness of alternative emission control technologies can be considered as a factor in selecting the final project design. Generally, cost-effectiveness analyses consider discounted cash flow or an annualized cost over an assumed project life, relative to the emission reductions that can be achieved. The resulting cost-effectiveness factor is compared to a

cost threshold. If the threshold is exceeded, then the technology may be excluded from consideration. Typically, cost-effectiveness analyses are conducted in a “top-down” fashion, starting with the technology that is expected to result in the lowest emissions and eliminating options until a cost-effective or universally achievable solution is identified. Again, not all permitting agencies will allow for the selection of control technologies based upon cost-effectiveness, and even those that do consider cost-effectiveness may also apply basic achievable technology standards which include emissions control equipment, regardless of cost.

If the permitting agency allows technology options to be excluded based upon a cost-effectiveness demonstration, it will be advantageous for the project engineer or developer to fully understand both the capital and operating costs of each technology option. Most regulatory agencies offer guidance and models for conducting cost-effectiveness analyses. Regulatory agencies may also provide generally accepted values for items such as construction overhead costs, but the project engineer most likely has a better idea of what the costs attributed to each technological option may truly be in his locality. Table 12-2 includes a list of the types of costs that are typically considered in a technology cost-effectiveness analysis.

Air Emissions Inventory

Once the project’s operating schedule, CHP system configuration, and control technology are selected, the applicant and permitting agency can then proceed to develop an emissions inventory. The inventory serves as the foundation for completing any additional impact analyses and compliance assessments, relative to air quality. Depending upon permitting requirements, the emissions inventory may include any or all of the pollutants identified in Table 12-1 and is intended to reflect the project operating loads and schedule as proposed by the engineer or developer. Emission factors from vendors, clearinghouses, and other data sources are also used to compile the inventory.

The project engineer or developer should be prepared to discuss inventory structure and protocol with the permitting agency prior to initiating work on the emissions inventory. The structure of the inventory will be dependent upon the permitting agency and the rules or policies that are driving its development. Normally, the inventory will reflect potential peak and average hourly emissions. If the project engineer or developer is expected to determine health risks and ambient air quality risks attributable to the project, then average annual emissions will also likely need to be quantified for the inventory. Monthly and quarterly emission profiles may also be needed based upon applicable regulations and policies.

Analyzing Air Quality Impacts and Determining Compliance with Applicable Regulations

The emissions inventory serves as the first step in determining the project’s environmental impacts. The following steps, such as dispersion modeling, air quality impact analyses, and health risk assessments, may not be required in all cases. Where these additional analyses are required, the permitting authority may assume responsibility for their completion. The project engineer or developer should confirm that these analyses are required and confirm who is responsible for their completion. Ultimately, these analyses will be combined with the previously discussed technology assessment to serve as the foundation for an assessment of compliance with applicable laws, ordinances, and regulations.

Cost Category	Considerations
Capital Costs	
Emission control system direct capital cost	Include sales tax, instrumentation, freight, and other capital costs for the control equipment. In some cases, the installation of control systems will also result in the need for continuous emissions monitoring system (CEMS). In these cases, the costs of CEMS must be included
Installation cost	Include items such as foundation, handling, erection, electrical, piping, ductwork, and insulation. Costs are approximately 30% of equipment cost
Indirect capital cost	Include engineering, construction/field expense, contractor fees, start-up costs, performance tests, contingencies. The default assumption is that costs, excluding performance test, are approximately 20% of equipment cost, and that performance tests are another 1%. The cost of regulatory tests upon equipment commissioning may be higher than the default, especially if emissions monitoring systems are installed and must be certified
Emission mitigation cost avoidance	In some cases, emission increases are mitigated through the purchase of emission reduction credits. If the use of technology reduces these costs, the foregone costs may have to be credited against the other capital costs of the project
Operating Costs	
System maintenance costs	Include direct labor, supervisory and consumable materials costs
Fuel penalty costs	Include costs incurred due to reductions in operating efficiency attributed to the control technology and the additional cost differential if higher-cost fuel alternatives are utilized
Annual reactant costs	Include costs for ammonia, urea or other reactant
Annual emissions verification	Include cost for control system tests and additional regulatory compliance tests that would not otherwise be needed
Catalyst cleaning and replacement	Include an annual allowance to account for the cost of periodic cleaning and replacement of catalyst (materials and labor). Include disposal fees, if any
Utilities	Include cost of electricity, water, and other utilities needed to operate the emission control system
Indirect operating costs	Include overhead, taxes, insurance, and administrative costs. Costs are typically 65% of operating labor, supervisory labor, and materials cost

TABLE 12-2 Control Technology Cost Analysis Considerations

Air Dispersion Model

Both the ambient air quality impact assessment and the risk analysis are based upon an air dispersion modeling analysis. Generally, the exhaust plume of a CHP system will be concentrated upon exiting the stack, but disperses in a bell-shape pattern as it travels downwind. The Gaussian algorithm can be used to estimate the dispersion of the plume. Computer models such as U.S. EPA's Industrial Source Complex Short Term (ISCST) and the American Meteorological Society/EPA Regulatory Model (AERMOD) incorporate the Gaussian algorithm to estimate the diffusion properties of the exhaust plume, and also take into account exhaust velocity and temperature. These models also consider meteorological and topographical characteristics that are unique to the project location. Once the project's plume dispersion is understood, then the concentration of specific pollutants at specific locations surrounding the project can be analyzed to determine the associated air quality impacts and potential health risks.

Air Quality Impact Analysis

Table 12-1 provides a summary of the impacts of various pollutants. Regulatory agencies often establish health-based standards for ambient concentrations of pollutants such as NO_2 , CO , SO_2 , and PM . They may also restrict the degree to which a project can contribute to existing ambient concentrations of these pollutants. If the concentration of a pollutant from a CHP project are likely to cause an ambient air quality standard to be exceeded or if it significantly adds to what is already a violation of an ambient air quality standard, the CHP project could be rejected by the permitting authority. By using a dispersion model to determine downwind exhaust dispersion properties, combined with the emissions inventory, it is possible to estimate the project's contribution to local or regional ambient air quality and determine the off-site concentrations of a pollutant that originates from the proposed CHP project. The modeling analysis can also demonstrate the anticipated cumulative concentration of a pollutant from both the proposed project and existing sources.

Health Risk Assessment

An additional assessment may be required to estimate the health risks that can be attributed to a CHP project. Health risk assessments rely upon the air dispersion model results, combined with the hazardous pollutant emission inventory, to determine peak short-term and average long-term pollutant concentrations at locations where people may live and work (receptors). The concentrations are then measured against pollutant-specific toxicology data to determine the increased health risks attributed to each pollutant. The toxicological data are published by health agencies and generally reflect the results of empirical studies.

Three types of health impacts are typically analyzed. The most common is an assessment of increased cancer risk that may be expected for nearby receptors. This risk exists due to the extended exposure to certain pollutants over a lifetime. A cancer risk assessment may include a determination of both individual risk and the cancer burden of an entire community (number of potential cases, based upon individual risk). Additional analyses may also be required to identify chronic noncancer health risks that are attributed to long-term exposure to certain pollutants. Finally, analyses may identify acute health risk that may be attributed to short-term exposure to certain pollutants.

Compliance Assessment

Once all of the technical analyses and assessments are complete, the applicant can proceed to conduct a regulatory compliance assessment. This assessment provides a more detailed explanation of how the CHP project can be expected to comply with applicable regulations. It takes into account the equipment selection, operating schedule and emissions inventory. It also takes into account any additional analyses that may be required, such as the air quality impact analysis and health risk assessment.

As the CHP project is further detailed and its operations better defined, various analyses are conducted, and regulatory compliance is assessed. Accordingly it is likely that certain additional mitigation measures may be needed to offset the project's impacts. Mitigation measures may include purchasing emission reduction credits to offset increases from the project, the addition of emission control systems, voluntary reductions in operating hours or operating load, and the installation of higher-than normal exhaust stacks to aid in exhaust plume dispersion. These measures should be anticipated in planning for the regulatory analysis. In most cases both voluntary and mandatory mitigation measures will be specified in permit conditions to ensure that the permitting agency can enforce the project's compliance with local regulations and policies.

Noise

Noise considerations are also critical to CHP projects. The permitting agency will typically have to ensure that the project does not result in noise levels that exceed local ordinances or building codes, and that the CHP project does not otherwise cause a nuisance to local residences and businesses. Combustion sources such as gas turbines and reciprocating internal combustion engines can be significant sources of noise at a CHP plant because large volumes of mixed air and engine or combustion turbine are transported at a high velocity through the exhaust system to ambient. The mechanical functions of engine or combustion turbine operation also add to projected ambient noise. Ancillary devices such as compressors, pumps and air handling systems can also contribute to higher ambient noise levels.

Noise Characteristics

Sound pressure, the acoustical energy emitted by the sound source, is the component of noise that is measured and regulated. Sound pressure is measured in decibels (dB) and reflects the force of the sound wave on a surface perpendicular to the sound. The decibel scale is logarithmic with sound intensity increasing by a factor of 10, so small increases in decibel represent much larger increases in sound intensity. Ten decibels is 10 times more intense than 1 dB, but 20 dB is 100 times more intense than 1 dB. While the decibel system is an objective measurement of sound pressure, human perception of sound (loudness) is subjective and is also restricted by sensitivity to particular frequencies. To the human ear, each 10-dB increase in sound pressure generally seems only twice as loud.

Table 12-3 summarizes the sound levels and effect of several typical sources. A sound level of 10 dB is barely audible to the human ear. The noise from a source is considered intrusive at a level of 60 dB, which is about the same level of noise that is emitted by an air-conditioning unit. Extended exposure to sounds at 90 dB (the level that is experienced near heavy vehicle traffic), can cause hearing damage. Pain and irreversible hearing damage can occur if exposed to higher noise levels above 120 dB.

Sound	Noise Level (dB)	Effect
	0	Hearing begins
	10	Just audible
Library	20	Very quiet
Light traffic (100 ft)	50	Quiet
Air-conditioning unit	60	Intrusive
Freeway traffic	70	Annoying
Heavy truck or city traffic (50 ft)	90	Very annoying, hearing damage after 8-h exposure
Auto horn (3 ft)	120	Maximum vocal effort required
Air raid siren	140	Painfully loud
Rocket launching pad, no ear protection	180	Irreversible hearing loss

Source: Adapted from various sources, including the Noise Pollution Clearinghouse.

TABLE 12-3 Sound Levels and Human Response

Sound pressure at any receptor point reflects not only the absolute power of sound, but also the characteristics of sound waves after they leave the source and travel to a receptor. As sound waves travel from the source to the receptor, they expand and lose intensity in much the same way air pollutant concentrations lose intensity as they migrate from the exhaust stack. For example, a sound pressure level of 70 dB at the source would be diminished at a distance of 50 ft to a level of 46 dB. In other words, an intrusive sound at its source would be considered to be relatively quiet at a farther distance, due to the loss of intensity over space.

In addition to the distance between source and receptors, terrain, vegetation, and the presence of structures also alter the intensity of a sound wave as it reaches a receptor. Various modeling tools exist which allow the project engineer to estimate sound pressure at various receptor points. Some models incorporate the Gaussian function, while other incorporate enhanced nonlinear estimating functions that may provide a more accurate estimate of sound distribution. Use of these models will support the development of a strong application, should the permitting agency require demonstrations of expected compliance with noise standards.

Noise Standards

Noise thresholds are more apt to be regulated through the enforcement of local ordinances, rather than national or regional regulation. While noise thresholds vary by locality, they do tend to consistently be more stringent in areas with sensitive receptors. They also tend to be more stringent during critical periods of the day. For example, the City of Seattle, Washington, enforces a noise ordinance which limits the maximum permissible noise level of a source to 55 dB if the source and receptor are both located in a residentially zoned neighborhood during daytime hours (7:00 a.m. to 10:00 p.m.). If the source is located in an industrially zoned neighborhood, but the receptor is in a

residential neighborhood, then the permissible noise level is 60 dB. If both the source and the receptor are located in an industrial area, then the permissible noise level is 70 dB. The Seattle ordinance also specifies noise thresholds for residential receptors during critical evening and weekend hours that are approximately 10 dB lower than the thresholds that are enforced during daytime hours.

Local regulations may also address critical period noise by specifying a daily weighted average noise threshold, in addition to identifying a peak daytime noise threshold. The daily weighted average threshold may account for source activities over a 24-hour period, but place a higher weighting value on those activities that occur during critical evening and early morning hours. The county of San Diego, California enforces a noise ordinance that limits peak noise exposure in a mixed-use land application to 50 dB from 7:00 a.m. to 10:00 p.m. and 45 dB for the remainder of the day on a 1-hour average, but also specifies a 24-hour weighted average limit of 10 dB for some locations. Because of the 24-hour weighted average limit, plants that are operated continuously would have to be designed to more stringent standards than similar plants that operate only a few hours per day.

Noise Mitigation

Engine manufacturers can provide various levels of silencing systems that significantly reduce noise levels. Exhaust stacks of gas turbines can also be designed with noise silencing features. The height of gas turbine exhaust stacks also helps to lessen the impact of turbine combustion-related noise on ground-level receptors. Exhaust devices alone may not successfully abate noise impacts. Other components of CHP systems such as pumps, compressors, fans, and air handling equipment also contribute to noise levels. The project engineer must also consider these sources when designing the plant. Ensuring ample distance between sources and receptors is critical to mitigating noise levels. Enclosures or other noise barriers may also be needed to comply with local noise limits.

Hazardous Material Transport and Storage

CHP plants that rely upon liquid fuel, such as diesel fuel or liquid propane gas, will also rely upon the transportation and on-site storage of these fuels. Some CHP plants will utilize SCR to reduce NO_x emissions. If the CHP system utilizes a gas turbine, the SCR system may use aqueous ammonia as a reactant that will have to be transported to the facility and stored until it is used. CHP facilities also utilize other hazardous materials such as solvents, lubricants, and coatings. The project engineer or developer should be aware of the potential environmental risks of transporting and storing these materials and address these concerns during the application process.

Liquid Fuel Storage

While diesel fuel has a relatively low flash point and does not pose significant risk of explosion, it does pose a risk to water resources, should it be spilled. A risk management plan may be required to ensure that secondary containment will be incorporated into the storage system to ensure that if a spill occurs, it can be recovered and will not otherwise enter the surface or groundwater systems. Impervious pavement may also be required at the point where fuel transfer occurs to prevent transfer to aquifers. Facility grades and rainwater collection systems also have to be designed to prevent contaminated storm water runoff to surface water systems.

Ammonia Transport and Storage

Although aqueous ammonia is typically diluted to a concentration of approximately 19 percent, it is still a hazardous material. Aqueous ammonia can easily evaporate if a significant spill occurs, the resulting ambient concentrations of ammonia can lead to serious health effects. Because of this risk, building codes and local ordinances may limit the amount of ammonia storage based upon proximity to property lines and sensitive receptors. The project engineer or developer may be required to conduct an assessment to determine the risk of ammonia spills, either during transport, or during on-site storage. The project engineer or developer may also be required to conduct an assessment to determine the health risk that would result from an on-site ammonia storage tank rupture. Secondary containment must be designed for ammonia storage tanks to ensure that spilled ammonia can be recovered. The containment reservoir must be large enough to accommodate the maximum volume of ammonia solution that is to be stored. Allowances must also be made for rainwater that may accumulate in the containment reservoir. Secondary containment surface area must be minimized to inhibit vaporization and ambient ammonia concentrations, should a spill occur.

Hazardous Materials

Hazardous materials will likely be generated and stored at the facility. Adequate steps must be taken to prevent spills that may migrate to waterways via surface water. The storage of hazardous materials will also necessitate the installation of emergency response devices such as eyewashes, showers, and spill cleanup kits. Finally, fire department personnel and other emergency response agencies must be advised of the volume and location of materials stored at the facility. A complete inventory of hazardous materials that may be stored on-site must be compiled and made available to emergency response personnel.

Other Potential Environmental Impacts

Most CHP projects are either incorporated into existing facilities or integrated into the overall design of new facilities, and most CHP systems are relatively small in nature. These characteristics help to ensure that environmental impacts, other than those already discussed in this chapter, will not become significant. Still, there may be occasion to address additional environmental impacts for select projects.

Construction Impacts

Construction activities can also result in excess air pollutant emissions, noise, and vehicle traffic. Air pollutant emissions include fugitive dust from disturbed soil during earthmoving operations and combustion emissions from construction equipment. Transportation of construction staff and equipment may lead to traffic congestion and additional air pollution. The permitting agency may require an assessment of the environmental impacts during plant construction and may also require mitigation measures and management practices to reduce environmental impacts.

Aesthetics

Aesthetics play an important role in community acceptance of an industrial project. Management of aesthetics goes hand in hand with measures that the developer may

implement to mitigate other environmental impacts. By taking aesthetics into consideration when designing buffer zones, sound barriers and enclosures that mitigate noise impacts, the project engineer or CHP developer may enhance the visual characteristics and acceptability of a project without significantly adding to project costs.

Environmental Justice

Environmental regulators are increasingly driven to ensure that CHP projects foster environmental justice. An increasing number of regulators are considering the balance of a project's environmental impacts, relative to existing environmental conditions and populations, and taking steps to ensure that the effects on local populations are proportional and balanced. Again, most CHP projects are relatively small and support host facilities that are already permitted or already constructed. The impacts of CHP projects in these circumstances are not typically expected to trigger environmental justice concerns, but such concerns can possibly exist, especially if the CHP project supports expanded facility operations that independently cause environmental and public health impacts.

Cultural and Paleontological Resources

Excavation for larger projects may present the risk of disturbing cultural or paleontological resources. The project engineer or developer should consult with local historical societies and preservation agencies to determine if such risks are likely to occur. Where the chance of disturbing these resources is significant, the project engineer or developer may be required to prepare a monitoring and response plan for implementation during earthmoving operations. These plans typically call for monitoring by qualified persons and in-place procedures for dealing with above resources that may be exposed with little advanced notice. Local agencies often require that artifacts, where encountered, be collected, catalogued, and promptly turned over to appropriate officials for safe handling prior to examination and public disclosure of findings. Delays to construction progress and project completion can be significant depending upon the extent of the area adjacent to the initial discovery site that may contain artifacts and the time required for careful examination of it by trained professionals, before any conditional contractor release to continue construction efforts is negotiated with interested third parties, if any, along with all agencies having jurisdiction.

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Construction

CHAPTER 13

CHP Construction

CHAPTER 14

Obtaining Operating Permits and
Implementing Compliance Management
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CHAPTER 15

Managing Risks during CHP Plant
Construction

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CHAPTER 13

CHP Construction

Milton Meckler

The construction of a CHP plant may require undertaking considerable risks to all parties involved. While most contractors are accustomed to dealing with risks, first time or less experienced CHP plant owner-operators are generally less informed about the risks they may encounter in the construction of a CHP project, and/or concerning the role they must be expected to play on the project construction team being assembled. This chapter is not intended to be a treatise on all the issues that contractors must normally address but is intended to address those issues that should be of principal concern in contractual relationships between contractor and their owner-developer clients when constructing CHP plants.

Owner-operators and/or developers of CHP facilities must be made to understand from the outset that their role during the construction of a project is as integral to its success as that of the design engineer, architect, and contractor. In addition, owners should also understand that there are virtually no risks on a construction project that cannot be shifted among the contracting parties depending upon the type and terms of the owner-contractor agreement. For example, an owner-operator may contractually be required to assume the risks of unusually severe weather, unexpected subsurface conditions, strikes at the turbine or engine supplier's manufacturing plant, changes in law or codes, increases in price, and delays to project completion associated with such risks.

Accordingly, the CHP plant owner-operator and/or his prime general or mechanical construction contractor must consider not only whether there is sufficient financing to complete its construction, for example, but also be prepared to conduct a thorough risk management review and analysis of the project structure and its contracting terms, while incorporating the following principal goals, namely:

1. Identify the most significant risks faced.
2. Determine how such risks can either be mitigated or entirely eliminated.
3. Conduct an assessment of the financial exposure should one or more of the major risks identified under (1) result.

The next section examines the steps that owner-operators and contractors of CHP projects can employ when undertaking a risk management review.

Gauging Contractor's Own Strengths

One of the most overlooked risks that contractors; particularly those where majority equity owners face uncertainties, is whether their firm has the requisite experience to build a successful CHP plant project. Some issues to consider in that regard are

1. Was the CHP plant project now on the table a natural outgrowth of the construction firm's prior experience?
2. What role did the construction firm play in that regard as a general contractor, construction manager, or specialty subcontractor?

From a risk management perspective, one should not assume that your particular experience in one or more utility power generation or industrial power distribution projects will allow you to be successful in CHP projects of any scale, or vice versa. Experience in hydroelectric, utility type power generation and/or waste-to-energy plants each involve their own specialties. The unique skill sets demanded of experienced contractors in each market who often face differing regulatory and code issues that must be carefully reviewed and thoroughly understood before starting the CHP contracting process.

Furthermore, the construction firm management team must begin with a careful and objective examination of its own key employee skill set, prior related project experience and technical capabilities in order to determine whether or not the staff and/or in-house supervisory crew is capable of constructing the CHP project being considered. Assume for the moment, that the initial assessment is positive but the firm is limited in the depth of its power generation experience.

An important consideration is if any of the firm's principal "equity stakes" executives and/or any of the firm's key employees familiar with the location of the project? As most experienced construction firm owners have learned from past experience, the success of any project can be affected by local conditions, for example, needed skilled labor availability, understanding of local codes, weather, and potential neighbor activism toward outside construction and utility-type projects.

If after looking at your current project backlog, the firm remains comfortable with its collective findings, namely that the firm is able to deal with the above matters, what, if anything, still needs to be done before deciding to commit the firm's resources to go forward with the proposed CHP project?

For one, the firm will have to take great care when assembling a project team that can be capable of overcoming any perceived weaknesses or lack of experience in a particular construction trade specialty as a result of current or other foreseeable new projects in the firm's pipeline.

CHP Plant Contractual Organizational Structure

One of the first steps a construction firm owner or key executive must take in going forward with a CHP project is to determine the organizational structure governing the relationships among the team members on the project, including the client owner-operator and/or developer, the design engineer, the architect (if new building facilities are involved), the construction manager, the construction supervisor, the construction inspector(s), construction trades foreman and additional subcontractors. A well-planned

organizational structure will greatly improve the success of the project and hopefully avoid many of the risks including potential scheduling and other trade issue conflicts normally involved in most construction contracting. Conversely, the lack of strategic planning and preparation can be counted on to make the CHP project more difficult, increase the likelihood of conflict, and reduce, or possibly preclude, the project's chances for success.

There is a variety of contract delivery methods available to an owner-operator or development firm involved in a CHP construction project. Accordingly, the construction delivery method must be chosen with a great degree of care to ensure that the overall goals of the owner are being achieved. Set forth below are among the most common construction contracting delivery methods used when the construction of CHP facilities of any scale are under consideration.

Traditional Design-Bid-Build Processes

Under a traditional method of competitive bid, negotiated contract with or without a guaranteed maximum price (GMP), either the CHP owner-operator or project developer hires an experienced prime engineering firm(s) to prepare the contract construction documents (plans and specifications) for the proposed CHP project. When the latter design services are completed, the CHP owner-operator or developer then hires a general contractor to construct the CHP project in accordance with above referenced construction documents.

The successful general contractor may choose to use some or all his own employees and/or also hire other laborers, general construction or specialty trade subcontractors and suppliers to perform portions or all of the work. During construction, the general contractor's field superintendent, specialty trade or general trades foremen, trained safety personnel, engineering professionals and the CHP owner-operator representatives monitor the ongoing construction work progress in a timely manner to ensure that the successful contractor is in general compliance with the design intent of the contract documents plans and specifications, which have been previously reviewed and approved by the local, state, or federal agencies having jurisdiction (see Chap. 12 for details).

Because of the technical complexity of most CHP construction projects, it may prove challenging to use the above traditional method of contracting. Owners want to have a facility that is guaranteed to achieve certain objectives related to output and emissions. Design professionals do not provide such guarantees in formulating designs, partly because this is outside the scope of their insurance coverage. On the other hand, the traditional general contractor does not provide such a guarantee only instead warranting that it will construct the project in accordance with the design tendered by the design professional.

Another concern is that because of the fast-track nature of the construction of an energy project, it may be difficult to have a design complete before construction starts. As a result, a contractor might be asked to bid off a set of plans and specifications that may be less than 100 percent complete, thereby, resulting later in disputes over whether items specified in the final design should have been assumed by the contractor in the original bid. This can result in major claims at the end of the project.

Design-Build Process

As a means of resolving the issue of guarantee, many CHP projects are constructed under the design-build form of contracting. Design-build also known as "turnkey" and

“EPC (engineer, procure, and construct)” contracts calls for one entity, known as the design-builder, to undertake the responsibility for both the design and the construction of the project.

CHP facilities are particularly appropriate for a design-build contract delivery method. First, design-build enables the owner to hold one party accountable both for the design and the construction of the entire project. A design-build approach brings the construction project much closer to being a product than under the traditional methods of contracting. This single-point contact not only relieves the owner of the need to coordinate the engineer and the contractor, one cause of construction disputes and overruns, but also enables the owner to specifically contract for performance guarantees relating to project.

It should be noted that there are several risks that an owner assumes when using the design-build contracting approach. For example, although the owner derives the benefit of having one party responsible for the complete development and construction of a project, the owner must rely solely upon that party for any recovery of compensation if something goes wrong. To counter this risk, many owners ask for financial guarantees or bonds from third parties so as to ensure that there is substance behind the construction organization. Others seek equity participation by the design-build entity as a means of ensuring proper project performance.

Another risk is that the design-build method eliminates the checks and balances that are present when design and construction are separate. Under the traditional approach, design professionals closely examine a general contractor's performance to determine whether it meets specifications and justifies payment. No such checks and balances exist when the design and construction are being done through one entity. Prudence suggests that an owner have his or her own in-house staff, or hire an outside engineering firm, to review the work of the design-builder and ensure that the product that is being furnished to the owner meets the owner's CHP project objectives.

Also, another risk is that under the design-build contract, the contractor has an incentive to provide the minimum acceptable quality that meets the owner-operator's project requirements and that will minimize call backs. It is, therefore, wise, if using the design-build method, for the owner-developer to be as detailed as possible with written requirements. As a minimum, the owner-developer should develop (or have developed for them) a basis-of-design document outlining the owner's project requirements. A better choice is for the owner to develop 30 percent design “bridging” documents that become part of the contract with the design-builder.

Finally, it should be remembered that a true design-builder is one who takes full responsibility for design. Some design-builders attempt to mitigate costs by performing large portions of the design in-house, and executing a contract that purports to be design-build. This can lead to arguments over whether the design-builder was merely completing the design, based upon assumptions of the owner-developer, or was fully certifying the adequacy of the entire design. In this situation, should the design-builder be responsible for extra costs arising out of that portion of the work designed by the developer? The design-build contract should resolve this issue clearly.

Integrated Project Delivery Process

Integrated project delivery (IPD) is a project delivery approach advocated by the American Institute of Architects (AIA) that attempts to integrate people, systems, business structures, and practices into a process that is intended to harnesses the talents and

insights of all participants so as to optimize project results, to increase value to the owner, to reduce waste, and to maximize efficiency through all phases of design, fabrication, and construction of the project. IPD teams can include members other than the traditional owner, engineer, and other integrated processes are also acknowledged and encouraged in sustainable ratings systems such as LEED®. IPD claims to provide the following benefits for the three major stakeholder groups.

Owner-Operators

Through continuous sharing of project data by employing advanced interactive software, that is, BIM and staying on top of ongoing project communications, CHP owner-operators are kept up-to-date as CHP plant designer alternatives and related cost are decided by remaining in a position to respond to choices in a timely manner thereby commencing early construction and improving sooner access to positive cash flow from CHP operations while expediting their project team's grasp of CHP owner-operator expectations. This should improve their team's ability to manage and control budgetary goals leading to improved schedules, lower life-cycle cost, and improved quality and sustainability.

Constructors

IPD also can enable constructors to apply their expertise when selecting construction methods earlier in the design process, hopefully resulting in improved project construction milestones and financial outcome. Enabling early constructor's participation in the design phase often results in strong preconstruction planning, more timely and informed understanding of designer intent, anticipating and resolving design-related issues, and visualizing best construction sequencing prior to the start of construction. After the start of construction, there is more likely improved cost control and budget management, all of which increases the likelihood that project goals, including schedule, life-cycle costs, quality, and sustainability will be achieved.

Designers

IPD also can energize improved communication and coordination among the various designers who can benefit from the early contribution of constructors' suggestions thereby avoiding constructibility issues later on. Furthermore through early application of value-engineering and interactive discussions, accurate budget cost estimates are more likely to lead to better design decisions, resolve preconstruction issues, improved project quality, and financial outcomes to all parties and a higher level of effort during early design phases, reduced overall documentation time, and improved cost control and project management, thereby improving the likelihood that project goals, quality, and sustainability are achieved.

Decision Makers

IPD clear documentation methods enable improved transition from traditional design deliverables. Furthermore IPD document process encourages the CHP owner-operator, design engineer(s), architect, and constructor to engage earlier into a collaborative team effort which can improve matters throughout the design and construction phases. The CHP owner-operator and architect/engineer team must agree to be bound by the terms of AIA B195 and A295 which should also assist the CHP owner-operator in early development of a list of prospective and qualified contractors.

The sooner a guaranteed maximum price (GPM) has been negotiated with the prime contractor the terms of their agreement follow AIA A195 and A295 procedures. During the detailed design phase the architect/engineer team members are encouraged to meet frequently with the CHP owner-operator and prime contractor to review developing design documents and revisit project budgetary constraints and goals. Meanwhile the architect must remain responsible for the integration and coordination of updated MEP, structural and constructibility information provided by the contractors and subcontractors.

Provision must always be made for adequate time to obtain owner-operator's written approval for all major decisions regarding the project program, schedule, construction cost and quality issues, in direct consultation with prime consultant (designated architect or engineer) and prime contractor.

Unfortunately no insurance product currently exists to efficiently manage loss for the company or the parties when the AIA C195, Standard Form Single Purpose Entity for IPD, is agreed on. Accordingly each party must be responsible for obtaining the standard insurance packages required in most other delivery methods. However, should each company member agree in advance to waive claims against all other team members, and a design defect or omission is discovered near construction completion but before the company is dissolved, difficult questions arise as to who is financially responsible and/or whose insurance will cover the loss if incentive compensation is judged to be insufficient?

Additional uncertainties also can exist after company dissolution such as "Which insurance coverage is then expected to be responsible for design choices made by consensus?" The matter of constructibility risk management and owner-operator satisfaction, etc. still remain unresolved as no insurance coverage is yet ready for CHP project teams electing to select this construction delivery method, particularly if they have not worked together in this manner before.

Identify the Appropriate Construction Delivery Method

A common oversight by an owner is to inadequately describe the contract delivery method that will be used on the project. For example, if the contractor will be acting as a design-builder, care must be taken to fully describe the design functions the contractor will be undertaking. Owners who fail to specify this in the contract may face an argument during construction that the contractor's design responsibilities were more limited, perhaps, for example, simply to reviewing the owner's performance requirements, than the owner originally intended. The owner should also specify what obligations the contractor will have for start-up, testing, commissioning, and operation and maintenance (as applicable) on the project.

Either the contractor, the owner-operator, or developer assumes responsibilities for arranging and purchasing insurance during the contract phase. Among the insurance contracts that are arranged during this phase are

1. *Construction all risks insurance.* Covers physical loss of or damage to the construction works or other property while at the site or during inland transit.
2. *Delay in start-up insurance.* Covers the financial consequences of delay in commencement of commercial operations caused by physical loss or damage to the works.

3. *Marine cargo insurance.* Covers physical loss of or damage to equipment and other supplies transported by air or sea.
4. *Marine delay in start-up insurance.* Covers the financial consequences of delay in commencement of commercial operations caused by a physical loss, damage, or disappearance during marine transportation.
5. *Third-party liability insurance.* Covers the legal liability of all parties arising out of bodily injury to or property damage of third parties.
6. *Each party involved in the construction project will also typically arrange for policies or fund for the following exposures:*
 - (a) Workers' compensation or employers liability, as appropriate for the jurisdiction
 - (b) Design engineers', architects', or other professional consultants' errors and omissions as prescribed by the contract
 - (c) Contractors tools and equipment
 - (d) Automobiles
 - (e) Employee dishonesty, fiduciary, and management liability exposures

Protection through the Construction Contract

In assessing who should bear the responsibility for construction risks, it is critical to remember that virtually any risk can be assumed for the right price. Consequently, one of the most important functions of a construction contract is to properly allocate the rights, responsibilities, and risks assumed by the parties to the contract.

Owner-operators need to understand that the goal of sound risk management is not to structure its contract documents so as to shift every unknown or potential site risk to the contractor. Such attempts do not go unnoticed and are more likely to result in inflated and unreasonable contract bids. The experienced and knowledgeable construction owner knows he must determine what risks his firm can live with, structure such risks into the proposal, and/or reflect such risk allocation in the construction contract on a most likely or worst-case basis.

For example, if a major piece of equipment is being shipped by air or sea, the project lenders may insist that marine delay in start-up coverage be purchased. Often, the equipment manufacturer will assume responsibility for purchasing the cargo coverage on the shipment. This therefore leaves the owner-operator in the position of having to purchase a "mono-line" coverage at often very steep rates. The most obvious solution is to try to package the cargo and marine delay in transit coverage. Assuming that the proper credits can be obtained from the manufacturer, this is an effective solution. An even simpler solution is to assess the exposure and explain it to the bankers. For example, assume the bank requires the purchase of this insurance for the shipment of a generator. If the generator is not on the critical path for operations and it can be demonstrated that a spare generator can be located and shipped in time to meet projected start date, the need for insurance or at least the initial required limits, should be minimized. This is simply an example of employing effective and proactive risk management techniques as discussed above.

Changes to Contract Scope during Construction

One of the major risks that an owner must recognize is that construction projects such as CHP facilities are rarely completed in precisely the same fashion contemplated by

the parties at the time of the agreement. This is because the circumstances and conditions which delineate the scope and parameters of a given project vary over time. In most cases, the parties have little or no control over these changing conditions.

Changes during construction may be required for many reasons, including

1. *Third-party requirements.* This may come in the form of governmental regulatory agencies or changes in the code or law.
2. *Owner-operator changing requirements.* For example, if the owner of a CHP project is also the host facility and decides to expand its manufacturing plant, it may need to change the project to obtain additional thermal output to support the manufacturing plant's expansion.
3. *Changes in technology.* This may occur if use of a particular process becomes less economical than recently developed alternatives; also, situations can arise where the technology specified by a contract is not compatible with actual conditions encountered.

Astute owners should insist upon contractual provisions which give them the flexibility to secure acceptable changes in the scope of work for a reasonable price. The changes clause of the contract typically allows an owner to direct unilaterally changes in (1) the drawings and specifications, (2) the manner or method of performance, (3) the time of performance, or (4) the equipment, materials, facilities, or services provided by the owner.

It is important for an owner to recognize that one of the most important points about the changes clause is the right to direct a change without the contractor's consent to the change. This allows the change to be made without giving the contractor the right to insist upon unreasonable time or money concessions as a condition to promptly performing the work. Nevertheless, the obvious risk to the owner is that by proceeding with the change in the absence of an agreement on price and time, the owner will face the risk of actual contractor costs being higher than the owner may have anticipated. Thus, even though the contract should give the owner the right to make unilateral changes, it is prudent to (1) discuss the change in depth with the contractor, (2) give the contractor adequate time to price the change and integrate the change into the work, and (3) to reach a lump sum price before the change is performed.

The "changes" clause should contain a procedure for determination of an appropriate equitable adjustment in the event the contractor is directed to proceed prior to an agreement on price or schedule. Generally, the contractor is entitled to be compensated for its additional costs to complete with a reasonable allowance for overhead and profit. Owners give some consideration to limiting overhead and profit to a percentage of direct costs. To ensure no misunderstanding, the elements comprising overhead, such as insurance, bond premiums and small tools should be precisely specified.

Where a change causes an increase in the amount of time required to complete the project, the contractor is entitled to a commensurate extension of the project schedule. It is prudent to include a contract provision stipulating that extensions are available only to the extent that the work affected by the change is on the critical path at the time and completion of the entire project is thereby delayed or extended.

Differing Site Conditions

One of the most frequent performance problems encountered on construction projects of any nature occurs when the contractor encounters unexpected site conditions.

In absence of a risk allocating provision for such unforeseen conditions, prospective contractors will, quite justifiably, increase the amount of their bids to cover possible costs associated with the contingency of encountering such conditions. Experienced construction owners will frequently attempt to allocate this risk by including a "differing-site-conditions" clause in the contract and providing data on subsurface conditions to prospective contractors.

Under a conventional differing-site-conditions clause, a contractor can generally recover additional costs incurred due to unforeseen conditions which materially differ from those shown in the contract documents, such as unexpected underground utilities. Recovery is also possible where actual conditions are of an unusual nature, differing materially from those ordinarily encountered on a project like that being constructed.

In the context of a design-build arrangement, the risk of differing site conditions creates an interesting dilemma. It is often the responsibility of the design professional to recommend and conduct a prebid site and subsurface investigation. Consequently, if a design-build contract incorporates the conventional differing site conditions concept, the design-builder may benefit by conducting an inadequate investigation.

Parties to design-build contracts for construction of energy projects may want to resolve this dilemma by negotiating a contract provision specifying an economical and prudent site investigation program to be undertaken by the design-builder. Thereafter, if actual conditions materially differ from those revealed by the design-builder's investigation, the design-builder would be entitled to an equitable adjustment for additional costs incurred.

Under this proposed arrangement the owner can avoid paying a windfall in the form of a contingency amount included in the design-builder's bid to protect against the possibility of unforeseen conditions which may never materialize. The contractor's risk is reduced since it can expect additional compensation if unforeseen conditions are experienced and, as a result, its overall price should be lower. As an alternative, owners should consider paying the design-builder to perform a detailed predesign site investigation prior to contracting for design-build services. Owners who insist upon requiring a design-builder to fully assume the risk of unforeseen conditions should expect to pay a sizable premium.

Another issue is the potential risk of the presence of contaminated soil or waste generated from the host facility, particularly if the host is a refinery or user of hazardous materials. In absence of a specific contract agreement, there is a question as to whether the presence of waste material would be a differing site condition so as to justify relief to the contractor. Because of the potential magnitude of dollars associated with a cleanup plan, the parties should agree who, as between the owner and contractor, will bear the risks of this cleanup.

Force Majeure

Virtually all modern construction contracts contain provisions which excuse the contractor's failure to perform where the failure is due to causes beyond its reasonable control. These are known as force majeure provisions. These provisions specify the events that are deemed to be beyond the control of the contractor, which will justify a time extension to the scheduled date of plant completion. Typical force majeure events may include floods, civil unrest, governmental or military authority take-over, insurrection, riot, embargoes, strikes, acts of God or the public enemy, or unusually severe weather.

Some specific performance problems are peculiar to CHP projects and may impact the force majeure clause. For example:

1. *Approvals or permits from regulatory and environmental agencies.* In order to avoid disputes over whether the delays to this process are excusable, the contracting parties should define which, if any, regulatory delays will constitute force majeure events; it is also important to determine whether such delays are compensable, or whether the contractor is simply entitled to a time extension.
2. *Technical problems at the host facility.* This can be a critical issue, since work may be stopped for reasons beyond the control of either the owner or the contractor.
3. *Equipment delivery delays.* Many owners on CHP projects specify that certain major items of equipment, such as a turbine or engine, be supplied by a designated manufacturer; these major manufacturers typically use their own standard form contract provisions which broadly define force majeure; in these cases, the parties should consider whether to incorporate a separate force majeure provision for the work and equipment supplied by these major manufacturers.

Liquidated Damages

When construction projects are not completed on time because of the contractor's unexcused delays, it is frequently difficult to calculate the amount of damage to the owner. Furthermore, even if actual damages can be calculated, the calculation can be the subject of major disputes between the owner and contractor. Therefore, to avoid the risk of being unable to prove actual damages, it is prudent for an owner to insist upon a liquidated damages clause that stipulates the amount of damages for each day of delay to project completion.

There are several issues associated with these types of clauses of which an owner should be aware. First, courts will require that the liquidated damages be a reasonable forecast of damages to be actually incurred by the owner and that they are not a penalty. A well-drafted liquidated damages clause should expressly acknowledge that delays will result in owner damages, which are difficult to determine and that the parties agree to the stated amount.

It is also advisable for owners to remember that liquidated damages are not to be a substitute for the damages incurred in completing a contract, where the contractor has defaulted or abandoned the contract. In these cases, actual excess completion costs may be recovered in addition to liquidated damages. The contract should expressly delineate such rights to the owner.

Performance Guarantees

One of the unique features of a CHP construction contract is that the owner generally seeks, and the contractor is willing to provide, performance guarantees for certain aspects of the facility. These guarantees may relate to electrical and/or thermal output, noise emissions, air emissions, fuel efficiencies, or myriad other aspects of the plant that are critical to achieving the financing or technical objectives of the owner.

There are several risks that an owner should remember when insisting on performance guarantees from its contractor. First the owner should ensure that a sound mechanism exists for determining whether the contractor has achieved the performance

levels required. This is typically done by specifying detailed testing and commissioning procedures. Among the items that should be addressed are the protocol for tests (which the owner should have the right to approve), acceptable tolerances in the test results, the duration of the tests and the remedies available in the event the test is not successfully completed. Commissioning should be by an independent third party hired by the owner. Hiring the commissioning agent as early as possible during the CHP development process helps reduce project risks.

Secondly, owners should recognize that the performance guarantee will be no broader than that specified in the contract. For example, an issue often arises as to whether the contractor will guarantee the performance of systems and subsystems in the facility, since a system may not be working properly (e.g., running in excess of capacity and subject to premature burnout) with the overall CHP plant producing output as required. Unless specifically addressed there will likely be no guarantee for a malfunctioning system other than typical warranty requirements.

A third risk is the level of guarantee versus cost of the guarantee. Contractors will charge a price for the guarantee being requested by the owner. Therefore, an owner should establish guarantees that are consistent with the overall operational objectives of the plant.

One method to achieve objectives is to use a "buy-down." Buy-down amounts are similar to traditional liquidated damages in that they attempt to compensate the owner for failures by the contractor to achieve output performance guarantees. In the event that performance guarantees are not met, by paying the buy-down, the contractor is typically relieved of further responsibility for schedule liquidated damages and for continuing efforts to successfully complete the performance tests. Owners should find this to be an acceptable alternative if the amount of the buy-down bears a reasonable relation to the diminished capacity.

Performance Bonds and Guarantees

One of the risks that an owner-operator faces is with the inability of the contractor to meet its obligations under the contract. A way to deal with this risk is to require that the contractor furnish payment or performance bonds. Performance bonds secure satisfactory performance of the contract and completion of the construction project. The surety is bound to the owner, to the extent of the amount of the bond, for the contractor's obligation to finish the project on time and in a workmanlike manner. Payment bonds are written for the benefit of subcontractors, and ensure that the subcontractors will be paid for their services on the project. This is especially helpful in states with liberal mechanic's lien statutes.

Some owner-operators are willing to waive bonds in favor of a guarantee from a third-party that the contract will be completed in accordance with its terms. From an owner-operator perspective, this guarantee should be sufficient to protect it from the financial consequences of a contractor default.

Effective Project Management

Many risks that an owner faces can be avoided if those responsible for contract administration on behalf of the owner follow some basic rules of sound project management.

Scheduling

The owner-operator of a CHP plant should have a strong understanding of the scheduling methods that will be used by the contractor to undertake the program for

construction and complete the CHP project in a timely manner. Sophisticated methods of scheduling, such as the critical path method (CPM), are widely used to plan activities and forecast critical delays. When properly used, the project schedule is a management tool that enables the owner to obtain advance warning of situations that may threaten the profitability of the project.

A question that is frequently asked in the scheduling area is whether or not the owner-operator should approve the schedule of the contractor. There are compelling reasons as to why an owner-operator should not approve the schedule. Several courts have held that if the parties agree that the CPM schedule is a reasonable plan for performing the work, the schedule is presumed correct. Because the owner-operator has no control over construction means, methods, man-hour loading or economic restraints, it is virtually impossible for an owner to be in a position to vouch as to the validity of the schedule. Nor would an owner want to be responsible for the contractor's schedule, since the owner's true concern should be the date that completion milestones will actually be met not how the contractor intends to achieve such milestones.

It is, however, critical for the owner-operator to evaluate the schedule and determine whether the owner is being required to perform services in a manner consistent with the terms of the contract. For example, the schedule could call for a turnaround time on approvals of submittals in a shorter time than is reasonable, placing the owner-operator in a position of delaying the contractor. Moreover, care should be taken to determine if the dates for bringing fuel to the site (which typically the owner-operator or developer's responsibility) is consistent with the other agreements the owner has entered into for the CHP project.

The project schedule should also be used as analytical device claim recognition, preparation, and as proof. This will enable the owner-operator to have objective data as to whether delays are excusable under the contract, and will allow the owner to determine in advance if the project will be delayed by proposed changes.

Special care must be taken by the owner-operator who has assumed the risk of contracting with various parties, such as equipment vendors and an erection contractor, to complete the construction of the project. In these multi-prime contracting projects, the owner is generally considered to assume duties analogous to those of the normal prime (general) contractor with regards to schedule and coordination of the work. The owner-operator's responsibility in this regard includes taking steps to require timely completion of one prime's work to prevent delay or interference to another prime contractor, as well as scheduling work in a way that will allow each subcontractor to perform economically where their respective work physically interrelates with that of other subcontractors.

Documentation

Another important administration tool for avoiding risks on the construction project is the creation, transmittal, control, and retention of project records and documents. During construction, a construction owner should establish and maintain systems that (a) identify the type, quality, frequency, and distribution of the records to be handled, (b) ensures that disciplined standards of documentation and proof are maintained, and (c) ensures that records are being preserved daily on every element of project administration and performance to permit a third party to reconstruct the project from the files, if necessary.

The records maintained on the project should include general correspondence, schedules and updates, minutes of job or coordination meetings, daily and weekly reports, memoranda for record, job diaries, progress photographs or videos, test and inspection

reports, and weather data. Also important are accurate records on change orders, shop drawings, and payment applications. Job records are the principal source of evidence for resolving disputes and minimizing the potential for claims.

In the event delay or disruption is being claimed by the contractor, the owner's job-site staff should attempt to prepare internally an analysis of the causes and effects of the problems. If records are well-kept, they will assist in the practice of preventive contract administration. You will not only be well informed about the contract's performance history, but will also be better able to anticipate problems before they arise or become critical.

Innovative Dispute Solution Techniques

Despite all the precautions taken by the parties in negotiating the items of work and detailed project requirements, disputes can and do arise. Because litigation and arbitration are generally in no party's best interest, an owner should consider alternative dispute resolution techniques that are designed to handle the dispute quickly and cost-effectively. However, the first, best, and typically most cost-effective step is to put emotions aside, sit down, discuss the issues and arrive at a fair, reasonable, and equitable resolution of the dispute.

Mediation

If the parties cannot come to agreement on their own, mediation is a process that is being increasingly used in construction disputes. The mediator acts as a facilitator but generally has no authority to render binding decisions. In order for a mediation to succeed, the process demands full participation of all parties, represented by individuals with settlement authority. In addition, it is critical for the parties to have an unbiased decision maker involved to promote the settlement of the case.

Mini-Trial

The concept of a mini-trial has also gained increasing acceptance in complex litigation. The name is somewhat of a misnomer in that a mini-trial is not a trial at all. Instead it is a structured settlement procedure and is usually voluntary and nonbinding. In essence, the parties present the salient elements of their claim during a limited period of time. A summary of the evidence and relevant law is then presented and the "decision makers," consisting of a principal of each disputing party and a neutral advisor, attempt to render an opinion.

Project Dispute Board

Another method of resolving disputes on the construction of CHP facilities is to establish, at the outset of a project, an individual or team of individuals capable of analyzing the technical and legal merits of project disputes. This concept has worked well on large construction projects, particularly if the dispute board meets regularly and is apprised of the CHP's project progress.

Conclusions

Owner-operators, developers, and contracted builders of CHP facilities should recognize that by carefully reviewing the project before construction starts risks will be identified and contingencies made for dealing with such risks during contract performance.

All parties need to perform a self skills evaluation and carefully evaluate the challenges, risks, as well as opportunities. CHP owner operators need to understand various project delivery methods and their respective advantages and disadvantages, and determine which is in their facility's best interest. All parties should understand all contract provisions, and those contract provisions must cover common construction scenarios, such as changes in the work, as well as conditions specific to CHP plants such as thermal and electric output performance guarantees. The contract provisions should properly balance risks and responsibilities so that the lowest project costs are achieved. Effective project management, by all team members, is a key component of a successful CHP plant project.

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Obtaining Operating Permits and Implementing Compliance Management Programs

Karl Lany

As a CHP project evolves from construction to a commercial operation, the project developer and owner will be required to ensure that operating permits are in place. They will also be required to demonstrate that the system will be in compliance with those permits and applicable regulations by completing prescribed commissioning activities and by implementing environmental monitoring systems and compliance management programs.

Commissioning the CHP System

Construction permits are typically written to allow for temporary operation of the CHP system until the final operating permit is issued. Occasionally, the permitting agency will require a second application submittal to allow for permanent operation of the CHP system, even though operating conditions may be included in the construction permit. The owner, project engineer, and developer should take steps prior to commissioning to understand the entire permitting process and ensure all application requirements are met. Failure to submit all applications could result in delays in commissioning, a violation of applicable regulations, as well as fines.

Prior to system commissioning, the developer, owner (permit holder), and system operator should have reviewed the construction permit to ensure its accuracy, and to fully understand all conditions related to commissioning activities and operation of the CHP system. Construction permits will normally include provisions for notifying the regulatory agency of construction milestones and system start-up date. The permits will also include specific activities that have to be completed as part of the commissioning program. The air

quality permit will generally dominate the environmental management tasks that must be undertaken during plant commissioning by specifying a test program to determine emission levels or to certify emissions monitoring equipment. These demonstrations will likely occur in conjunction with other plant start-up and commissioning activities. The permit will also specify the basic components of a compliance monitoring and management program that must be implemented as the CHP system is commissioned.

Continuous Emissions Monitoring System Certification

Construction permits that are issued by air quality agencies may specify the installation and certification of a continuous emissions monitoring system (CEMS). Certification of the CEMS includes steps to demonstrate system reliability and accuracy. These steps, as well as system performance specifications, are often identified in environmental regulations, or in independent agency standard documents. The U.S. Environmental Protection Agency (EPA) regulates CEMS design, accuracy standards, and quality assurance practices through the Code of Federal Regulations (40 CFR 60 and 40 CFR 75). Local regulatory agencies in the United States may also enforce additional CEMS standards.

Various CEMS design and management standards exist outside the United States and certification to these programs is required in most foreign applications. For instance, the Environment Agency of the United Kingdom enforces CEMS through method implementation documents and the European Union issues directives that specify how emissions are to be monitored for variety of sources. When CEMS are called for in these directives, standards for design, installation, and maintenance are also specified. Independent organizations such as American Society for Testing and Materials (ASTM), International Organization for Standardization (ISO), and TUV Rheinland also specify standards for CEMS or certify performance of CEMS components. Regulatory agencies may defer to these standards when authorizing the installation of a CEMS.

System Specification Submittal

CEMS certification is dependent upon the developer delivering complete specifications of the system and committing to quality assurance procedures. The developer must provide the regulatory agency with data demonstrating that the monitoring system is designed to meet all technical requirements specified by the agency. If submittal of the data is not part of the initial CHP application process, it will likely occur at another point just prior to construction and operation of the CHP system. The submittal should specify which parameters of the exhaust stream will be monitored. Most CEMS are installed to monitor NO_x and CO concentrations. Because concentrations are specified at standard conditions, the monitoring system will also include components to measure exhaust diluents such as O_2 or CO_2 . If the construction permit specifies mass emission rates, then the CEMS may also include components to measure exhaust flow, or to calculate exhaust flow based upon measured fuel flow. Efficiency-based emission standards (lb/MW-h or kg/MW-h) will also require the integration of power output data from the CHP system with output data from the CEMS.

The developer should also identify the model number of all major system components such as analyzers, sample conditioning systems, and metering systems. It may also be necessary to identify the serial numbers of critical system components. Measures taken to control the monitoring system and operating environment should be identified, and all technical data should be supplemented with vendor specifications and installation drawings.

The CEMS is also dependent upon the operation of a data acquisition system. The submittal should include a summary of how data will be managed and reported and should be supported by a data flow diagram. Applicable equations used to calculate emissions should be identified along with references to applicable regulations. A description of the computer that will run the CEMS software should be included in the submittal.

Quality Assurance Plan

The ongoing accuracy of a CEMS is greatly dependent upon adherence to effective maintenance and operating procedures. The developer will be required to compile a quality assurance plan for delivery to the operator. The plan may also have to be reviewed and approved by the regulatory agency. The plan should outline steps for ensuring system reliability and data accuracy. These steps include daily system calibrations, periodic calibration gas audits, and periodic relative accuracy test audits. Procedures for completing these tasks should be supplemented with an operator's compliance schedule.

The quality assurance plan should include preventative maintenance procedures and corrective actions. Maintenance procedures should be supplemented with an activity schedule and a spare-parts list. Corrective actions should include applicable procedures for notifying facility management and regulators of system malfunctions that may affect data availability or accuracy. Contact information (support contractors, plant management, and regulatory agency) should also be identified in the plan.

Initial Reliability and Accuracy Demonstration

To commission the CEMS, the developer will have to demonstrate its reliability and accuracy. This is done through a series of tests that occur over several weeks. The first test is intended to demonstrate that the CEMS can be operated continuously and reliably without intervention or adjustment. This "hands off" test typically lasts for a period of at least 7 days. During the second test the CEMS must demonstrate the ability to maintain acceptable calibration over a second 7-day period. During this test, daily calibration checks of the system must consistently be within specified tolerances. If the CEMS fails either reliability test, conditions leading to the failure must be corrected and the test must be reinitiated.

Upon completing the system reliability demonstrations, the developer can proceed to demonstrate the system's relative accuracy. The accuracy test can be effectively conducted in conjunction with other emissions testing programs that may be specified in the construction permit. These programs are discussed in the following section of this chapter. During the relative accuracy test audit (RATA), CEMS measurements are compared to results of a simultaneous emissions test conducted by an independent laboratory over multiple 30-minute test runs. A minimum of nine test runs are typically required to ensure data validity. When compared, the results from the CEMS and the independent laboratory must be within specified tolerance and also be statistically significant. Upon successful completion of all commissioning tests, data from the CEMS will be acceptable for demonstrating compliance with emission standards.

Initial Emissions Test

Emissions compliance tests are often required upon system start-up, especially if issuance of the construction permit is dependent upon the installation of emissions control systems or if the permitted operating schedule is dependent upon assumptions regarding the impacts of a specific pollutant. Emissions tests will most often be required

to confirm emission rates of criteria pollutants such as NO_x , CO, ROG, SO_x , and PM (see Chap. 7). In some cases, tests for specific hazardous air pollutants will also be required. Fuel analyses and fuel meter accuracy tests may also be required. The construction permit will most likely specify test methods to follow and time frames for completing the tests. Established test methods have been developed by various organizations including U.S. EPA, ISO, and ASTM International. Local environmental agencies may also develop test methods to be incorporated for projects in their jurisdiction.

Coordinating the Emissions Test

In some cases, the owner or developer will have full discretion in selecting a contractor to conduct the tests. In other cases, contractors may have to be certified by the regulatory agency. Finally, in a few cases the regulatory agency will conduct the emissions tests themselves. If the agency is not responsible for conducting the test, the test contractor will submit a test plan for agency approval. The test plan identifies field test personnel, pollutants to be measured, test methods, sample repetition, and sample period duration. The plan also identifies CHP operating conditions, stack configuration (including sample port location) and anticipated emission concentrations. Once the test plan is approved, the contractor can proceed with the test program, but may be required to notify the agency several days in advance. Notification is intended to allow regulatory agency personnel to witness the test and failure to notify the agency of an upcoming test could result in the test being disqualified.

The developer will likely be responsible for coordinating various contractors, regulators, and the system operator to ensure that the CHP system will be operated for an adequate amount of time to complete the tests. Depending upon the test methods specified by the regulatory agency, a test program may require from 1 to 10 (or more) hours to complete. The developer will have to ensure that the plant is capable of uninterrupted operations to complete the test. It may also be necessary to operate the CHP system at various loads to complete the test. The developer may also encounter other logistical responsibilities such as providing adequate test facilities and ensuring that the emissions test does not interfere with other commissioning and start-up activities at the facility.

Resolving Unacceptable Test Results

Ideally, an emissions test will demonstrate that the new CHP system meets permitted emission limits. In these cases, the developer and permit holder can proceed to finalize operating permits and turn over the system to the operator. Unfortunately, start-up emissions tests sometimes do not demonstrate compliance with permit conditions and corrective actions must be initiated. Corrective action may include obtaining temporary relief from permit conditions or regulatory requirements while the conditions that cause excess emissions are resolved. At this point in commissioning, the developer must involve the permit holder because only the permit holder will be able to commit to any compliance agreements with the regulatory agency.

To resolve unacceptable test results, the developer must understand what permit conditions or regulatory requirements may be violated. In some cases, a violation due to excess emissions may not occur until after the end of a period of 30 to 365 days. In these cases the developer may have time to correct the conditions that cause excess emissions and retest for emissions without ever being in violation. For example, a permit may limit PM emissions to a specified number of pounds per month, based

upon a maximum operating schedule and assumed hourly emission rate; but the permit would not necessarily specify the hourly emission rate. If the test shows that PM emissions exceed hourly rate assumptions, the developer can project that continued CHP operations would result in a violation at the end of the 30-day period, but the system would remain in compliance until then because there are no short-term limits in the permit to be enforced. If prior to the end of the 30-day period the CHP is demonstrated through a second test to emit at a lower rate, or if the developer reduces the operating schedule to maintain compliance with the 30-day limit, no actual violation would occur and no relief from the permit would be immediately needed (although coordination with the regulatory agency is warranted).

If the test results indicate emissions in excess of a concentration limit (ppmv or mg/m³), or a short-term mass limit (lb/h or kg/h), or a mass rate (lb/MW-h, or kg/MW-h), then the developer may have to temporarily shut down the CHP and the permit holder may have to seek temporary relief from enforcement of the permit or applicable regulation. Such relief can often be justified based upon the following conditions:

- Economic hardship of not operating
- Lack of alternative sources of power or heat to maintain facility processes or to preserve goods in process
- Critical public need for services supported by the CHP system such as hospitals, wastewater treatment facilities, etc.
- The need for system operations to identify the problem, and to subsequently demonstrate compliance

Regulators may also consider operator diligence and responsiveness when determining if relief is warranted. It is critical to demonstrate that the violation was unforeseen and beyond the control of the operator. It is also critical to demonstrate that prompt action was taken to try to avoid noncompliance and to advise the regulatory agency of the violation.

The process of obtaining relief from construction permit conditions may be as simple as coordinating with regulatory agency staff. In many cases, agency staff and management have authority to enter into compliance agreements with the permit holder. These agreements are sometimes referred to as stipulated orders or stipulated agreements. In other cases, agency staff and management may be precluded from granting temporary relief from permit conditions or regulatory requirements. In these cases, the permit holder may have no choice but to petition for relief through a public hearing. During the hearing the developer and the regulatory agency would be allowed to present testimony regarding eligibility and the need for relief.

Issuance of the Final Operating Permit

Once all commissioning activities are complete and compliance with permit conditions are demonstrated, the developer, operator, and regulatory agency can proceed to convert the construction permit into an operating permit. This point of the permitting process may be the last time that simple administrative changes can be made to the permit without an application submittal or fee payment. It is also at this point that commissioning requirements will be deleted from the permit, leaving only ongoing compliance conditions that the operator will be required to meet.

The Permit Conversion Process

Issuance of a final operating permit is generally initiated when the permit holder notifies the regulatory agency that construction is complete, but little action will be taken to convert the permit until after commissioning activities are complete and the regulatory agency has reviewed and approved test results. The regulatory agency may also wish to inspect the CHP facility prior to issuing the final operating permit to ensure compliance with permit conditions and applicable regulations. In some cases the operating permit will be subjected to additional review periods that will delay final issuance. During the conversion process, the construction permit will generally continue to serve as a temporary operating permit as long as all necessary applications have been submitted in accordance with regulations.

Final Permit Language

In most cases, the operator should expect the operating permit to contain the same conditions, other than commissioning conditions, which are contained in the construction permit. In a few cases, however, the operator may have an opportunity to fine-tune permit conditions based on the emissions test results. The most common of these cases occurs when operating schedules specified in the permit reflect assumed emission rates that differ significantly from the rates demonstrated during emissions tests. For example, the developer may have accepted a construction permit limit on the number of allowable operating hours per year, or the amount of fuel consumed per year, based on conservative default emission factors. If the emissions test demonstrates that the CHP system emits at a much lower rate than initially assumed, and if the operator is willing to commit to meeting lower rates, it may be possible to modify the operating condition to specify the lower emission rate and a higher operating limit. In some cases, permit modifications may also be made to increase the allowable emission rate, with complementary conditions that further restrict the annual operating limit, should the emissions test show higher than expected emission rates.

Implementing a Compliance Management Program

Many environmental permits do not warrant any type of commission test, but the developer may have to notify permitting agencies of system start-up and may also have to develop and implement compliance management program. In almost all cases, the installation of a CHP system will result in the need for internal processes to ensure compliance with operating permits and applicable regulations. In some cases, the operator must also submit compliance and risk management plans to regulatory agencies prior to, or shortly after, taking control of the facility.

Potential Plan Submittals

Various environmental management plans are typically required for a new facility, but the integration of a CHP with a new or existing facility warrants only minimal post-permit plan submittals. Plans that may be required, due to the added environmental or safety risks attributed specifically to the CHP system, include hazardous material emergency response plans and risk management plans for accidental chemical releases. These plans must be submitted prior to, or shortly after, initiating operation of the CHP system.

Hazardous Material Emergency Response

The operator must advise fire departments or other emergency responders of potential hazards at the facility. This is often done through the submittal of a plan that is often referred to as a Hazardous Materials Business Plan or a Business Emergency Plan. These plans identify key facility contacts and include an inventory of hazardous materials typically located at the facility, along with facility diagrams showing the locations where material is stored or used. They allow emergency responders to better understand the safety precautions that must be taken when entering the facility and the risks to the community that may result from an emergency at the facility.

Accidental Release Risk Management

When ammonia is spilled, it can vaporize and expose people in proximity to acute health risks. Regulatory agencies may require the operator to submit a plan to advise regulators and the public of the risks associated with an accidental ammonia release. Risk management plans typically identify the potential health risks attributed to a worst-case spill. These plans also identify risk prevention measures to be taken by the operator. These measures may include establishing delivery routes that bypass large population centers, designing storage capacities that are not larger than necessary, integrating features to prevent spills when transferring ammonia from a delivery truck to a storage facility, using vapor recovery systems when filling a storage tank, and designing secondary containment to minimize surface area and to allow for product recovery in the event of a storage tank failure.

Compliance Management Program

Environmental permits that are issued for a CHP system may contain numerous operating conditions. Additional compliance requirements may be contained in applicable regulations. Failure to comply with permit conditions and regulatory requirements can be detrimental to the CHP operator and the host facility. Violations of these conditions can lead to financial penalties and repetitive compliance failures result in increased scrutiny of facility operations by regulatory inspectors. To ensure compliance with permit conditions and regulatory requirements, the operator must develop and implement an effective compliance management program that includes established operating and maintenance procedures aimed at preventing equipment failures that can lead to noncompliance. The compliance management program should also include provisions for monitoring, recording, and reporting environmental compliance.

Operations and Maintenance Procedures

Sound operating and maintenance practices help to ensure compliance with environmental standards. The operator must develop and implement formal procedures to ensure reliable operations of the CHP system, including those components that are designed to reduce environmental impacts. Preventative maintenance procedures and a schedule of maintenance activities should also be incorporated into the formal procedures. These procedures are built upon those that are recommended by CHP equipment vendors, but may also include additional provisions that are specified in environmental permits and regulations.

Ideally, failures that may lead to an environmental upset or a violation of permit conditions would never occur. In reality, such upsets do occur and the manner in which

they are resolved can lead to direct enforcement consequences. Many environmental regulations include provisions for equipment malfunction that protect the facility operator from enforcement action if prescribed steps are taken to curtail operations, correct the malfunction, and appropriately notify the regulatory agency. Facility operating procedures should include provisions for responding to equipment malfunction and identify specific channels of communication between operators, supervisors, and the regulatory agency. Deadlines for corrective action, agency notification, and potential equipment shutdown should also be included in formal operating procedures.

Compliance Monitoring

The facility operator must develop and implement a monitoring plan that ensures compliance with permit conditions and regulatory standards. An effective monitoring program ensures that operating staff will take uniform steps on a regular basis to promote environmental compliance. If the plan is adhered to, it can help to prevent environmental upsets and can also demonstrate to regulators that the facility operator is diligent in managing environmental compliance. This demonstration may lessen the impact of enforcement actions, should an upset occur.

Emissions Monitoring

The use of CEMS is discussed in the preceding section of this chapter, but not all CHP facilities are subject to CEMS requirements. Compliance for many smaller systems can be adequately managed by monitoring various engine operating parameters on a daily basis. The operating permit will likely identify those parameters that help to demonstrate that systems are functioning properly and that compliance with emission limits can be expected. For reciprocating internal combustion engines, monitoring parameters often include air-to-fuel controller malfunction sensors, exhaust O₂ levels, accumulated operating hours and fuel flow rates (or accumulated flow). These parameters indicate if the engine is operating as specified, and also if operating throughput limits may be exceeded. If the engine operates in conjunction with a post-combustion emissions control device, the operator may also be required to monitor inlet catalyst temperature, and catalyst inlet/outlet pressure differentials. If the control system relies upon the use of ammonia or urea, the flow rates of these reactants may be monitored. These parameters help to demonstrate if the emission control system is functioning and if catalyst fouling may occur. In some cases, permits include power output based emission limits (lb/MW-h or kg/MW-h), and permits sometimes allow for more lenient emission limits when heat is recovered. In these cases, it may be necessary to monitor power output and heat recovery rates. If the CHP system is based upon the use of a gas turbine, the monitoring parameters will not differ significantly than those that are applicable to reciprocating internal combustion engines, except that there is no need to monitor oxygen or air-to-fuel characteristics.

In the absence of a CEMS, it may be necessary to monitor CO and NO_x emissions on a periodic basis using a handheld analyzer. Handheld monitoring devices are proven to be reliable and accurate indicators of emissions concentrations, but their use as an official compliance determination is dependent upon adherence to a stringent quality assurance program. Because of this practical limitation, periodic emissions monitoring programs are commonly used only to supplement, rather than replace, parametric monitoring and official source tests. If a periodic monitoring program is implemented, the operator must develop formal procedures for conducting tests and responding to

unfavorable results. Analyzer quality assurance procedures must also be developed. To develop these procedures, the operator should be able to depend on guidance from the regulatory agency and the analyzer manufacturer.

Other Compliance Monitoring Programs

The operator may be required to implement additional compliance monitoring programs that are unrelated to air quality. In some cases, existing compliance management programs for the host facility simply need to be amended to reflect the new CHP operations. In other cases, the introduction of CHP operations may require the development of new monitoring programs to manage environmental risks that did not previously exist at the facility. If SCR is used to control NO_x emissions, the operator will likely be required to periodically inspect the storage devices to ensure that pressure relief valves are operating appropriately, that and that leaks and spills have not occurred. Similar monitoring programs will be required if fuel is stored on-site to accommodate the CHP system.

Record-Keeping and Reporting

Record-keeping is a key component of any environmental compliance management program. Records that are maintained over long periods of time demonstrate compliance history and operating trends that may affect environmental impacts. A well-developed record-keeping program demonstrates that compliance management programs are in place and appropriately managed. Without access to compliance records, the regulatory agency would be forced to assume that mandated compliance management plans are not implemented, and that compliance with permit conditions and applicable regulations is not assured.

Operations monitoring logs must be developed to aid plant personnel in maintaining equipment and monitoring environmental compliance. Monitoring logs should identify each component of the CHP process to be monitored. They should also be designed to allow facility personnel to identify the date when monitoring is completed along with findings of the monitoring event. If facility personnel are to confirm compliance with specific operating parameters, the monitoring log should identify a range of acceptable values that performance will be measured against. If a CEMS is installed, it will be equipped with a data acquisition and handling system. This system logs key data such as pollution concentration and mass emission rates, daily calibration results and periods during which CEMS data are invalid or missing. This data is generally available to the facility operator and should be reviewed on a periodic basis.

Many critical compliance records are generated by parties other than the CHP operator. Records of contracted tests and inspections are also an important demonstration of compliance and they should be collected and maintained by the CHP operator. Examples of third-party records include emissions test reports, fuel and SCR reactant analyses, storage tank inspection reports, boiler inspection reports, and storm water analyses.

Not all compliance records need to be delivered to the regulatory agency. Many records are simply retained on-site and made available to the agency upon request. Record retention periods of 2 to 5 years are usually specified in applicable regulations. Occasionally, periodic compliance reports must be submitted to regulatory agencies. These reports may summarize the contents of facility compliance records, but do not include the records themselves. It is the operator's responsibility to understand which environmental compliance records should be retained and which records should be

submitted to the regulatory agency. Reporting requirements may be found in permit conditions, but may also be specified only in applicable environmental regulations. If regulations do specify the submittal of compliance reports or other compliance records to the regulatory agency, it is advisable to obtain receipts of their shipment and delivery. Copies of all records sent to regulatory agencies, including transmittal letters should be retained by the facility operator.

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Managing Risks during CHP Plant Construction

Milton Meckler

Risk management is a systematic methodology that can be used to both establish and quantify risks to which a proposed project may be exposed prior to commencing construction so that conscious decisions are undertaken on how best to manage foreseeable risks in order to ensure satisfactory performance of the CHP plant on its completion.

The aim of this chapter is to describe a technique which identifies the practical use of a probability distribution from which a line item cost prediction can initially be made on limited information and used by the successful contractor in assessing a particular line item prediction, and, eventually when all such items have been accessed, in deciding upon the feasibility of the proposed CHP plant construction project under consideration. The general risk management methodology options are applicable at any stage of investment appraisal, development appraisal, or design process of any CHP plant project.

If properly understood and executed, risk management allows one to go well beyond known insurable construction risks, but may not guarantee identifying all possible risks. However, rigorous risk management is far superior than to rely on one's intuition or past experience recalled from other completed central and related CHP plant construction projects, particularly when different in scope, interconnectivity, and/or complexity.

A further purpose of this chapter is to outline and acquaint both the experienced and beginning CHP plant contractors with some available and proven risk management options that others have found to be practical and cost-effective provided there is a willingness to use a disciplined approach to the most critical features of a CHP plant using one of several available structured risk analysis methods. In the final analysis, the depth to which you may wish to analyze CHP construction and plant performance risk is often a matter of one's common sense, judgment, and circumstance.

Although some risks are controllable, for example, lack of subcontractor coordination with each other or employees or with lack of timely processing of architect-engineer (A/E), MEP (mechanical, electrical, plumbing), civil, structural requests for information (RFI), or shop drawing review, other risks cannot be controlled. In addressing the uncontrolled risks, one can initiate the risk management process by tabulating the source of such initial risks, for example, adverse weather and inadequate on-site safety

inspection, followed by resulting events, for example, serious worker injury or death, followed by consequential effects, for example, OSHA citation(s), project delays, prosecution and fines, and future increased cost of insurance.

The uncontrolled risks may require contingency provision(s) to deal with above noted risks, with any contract liquidated damages liabilities, or with consequential owner delay loss or third-party loss by establishing either worst- or a lesser-case eventualities. On such matters, contractors must carefully distinguish sources of risks from the effects of risk and use common sense and experience in assigning contingency costs particularly in competitive bid situations. Where possible, owners can consider alternative negotiated design-build proposals from a short list prequalified and experienced general CHP engineering contractors to avoid costly change orders, to ensure timely ordering of key equipment, to limit unwanted substitutions, to avoid construction delays, and to help ensure CHP project delivery is on time and on budget.

Risk Management: The Insurance Industry Perspective

Managing the risk for a CHP plant can often be challenging particularly when state and/or federal energy policies are in transition and when market conditions reflect uncertainties of financing at reasonable cost, etc. Some of the key risk management issues related to the operation of CHP plants in a business environment may be undergoing restructuring as a worst-case scenario.

Insurance underwriters cannot deal with concerns about negotiating pending power sales contracts, current marketing studies, foreseeable area power growth needs or pro forma cash flow analysis. While dealing daily with the risks associated with construction of known entities, for example, hospitals, retail malls, and apartment and office buildings, insurance underwriters often find on-site CHP projects challenging when quantifying risk. Therefore, one needs to initiate an early and continuing dialog with one's insurance and risk management professionals to familiarize them with your depth of preparation and track record in prior successful CHP plant construction and profitable operation of private sector CHP projects, as applicable.

The following is a discussion from the perspective of the party responsible for developing a CHP project from the ground up, through design and construction including managing ongoing operations after start-up. In the initial project stages, one needs to

1. Clarify the differences between "risk management" and "insurance."
2. Identify the risks associated with a CHP power plant project.
3. Understand typical "insurance" policy concerns for above referenced project.
4. Meet with several insurance carrier representatives to discuss key issues with your risk manager and better understand current insurance marketplace for CHP plants.

When looking at risk, understand that insurance carriers generally assume that uncertainty is not good. Therefore it is in the best interests of the enterprise to minimize the probability of occurrence of those events or situations that contribute to uncertainty. Most early CHP plant developers looked at risk from the perspective of finding available insurance products to meet their perceived risk needs. For example, fire insurance is available, therefore, the, fire risk is "taken care" of by insurance. If a certain perceived risk was not insurable, then it was essentially ignored or internal contingency funding was established to handle the risk and added to the cost to construct.

The insurance risk and insurance manager takes a much different approach to risk. The managers look to the "circle of risk management" as a reference for dealing with the risks and exposures of the overall business enterprise. The "circle" metaphor was adopted because there is neither an end nor a beginning to the management of risk. As long as there are internal and/or external uncertainties, there will be the need to continually "go around" the risk management circle.

Next, one must understand the components of the circle in terms of examples of how these concepts are or should be applied. One must begin with the identification of all risks, not just the insurable risks. If the organization is interested in quantifying its total risk quotient, this identification process must go beyond the traditional areas of property, boiler, and liability. Survey, research, benchmarking, and creative thinking are just some of the methods used to identify risk. The key to determining maximum foreseeable and probable maximum losses is not to allow owner-operators or developers to "ball park" potential estimate for loss coverage needs.

After inventorying and quantifying the risks, underwriting and claims management needs to determine which exposures should be totally avoided. While often the least expensive of the steps, there could be significant missed opportunity costs associated with an avoidance strategy.

CHP plant developers are sometimes considered to be risk takers among many insurance carriers. Most responsible insurance executives are more likely to seek ways to maximize their return while still taking some risk. Yet insurance executives do not treat it as a "zero-sum" game, the conservative insurance risk management professional places greater emphasis on the minimization of risk. From their client's perspective, safety and loss control are considered expense items and relegated to client's nonoperational professionals who may not have the influence, control, or impact that they should on maintaining safe operating practices when faced with tight deadlines and growing project cost overruns.

Today's insurance loss control and safety specialists are required to minimize the occurrences of loss by considering both pre- as well as post-event loss scenarios. Loss control specialists also try to develop systems, procedures, and processes that reduce the frequency or occurrence of all foreseeable loss situations. Having sufficient fire protection, adequate spare parts, and an effective crisis management program are examples of what should be key components of an integrated risk management program for every CHP plant.

Often the easiest and least expensive way to deal with risk is to transfer it contractually by employing the power of the contract with owner or their subcontractors who may have been required to share to some degree the assumption of some risk. One's financial backers also do not want to assume any risk and seek to transfer it all to their borrowers. As long as there is a balance between the risks that are assumed via a contract and the risks transferred via insurance and clearly retained, the entity can forecast its cost of risk. When one side permits risk leakage or an imbalance to occur, an unmanaged exposure exists that could jeopardize the profitability, or even viability of any of the owners, contractors, architects, and engineers own firms.

Risk financing must also be addressed on the insurer's so-called wheel. Risk financing includes two basic components, namely, risk retention and risk transfer (via insurance).

The risk retention option, whether it is by self insurance (or self funding,) seeks to duplicate what a hypothetical insurance underwriter would undertake in a more sophisticated manner thereby avoiding the fictional costs associated with an insurance policy. Self-insurance is one way to buffer the risk for those presently unknown events likely to

occur based on past experience. While self-insurance does not have the underwriter's advantage of true risk spreading, the financially strong firm can take a long-term view of frequency exposures and make allowances for them as a routine cost of doing business. Transferring risks such as automobile or construction equipment physical damage or small component breakdowns is typically not cost-effective. Assuming the risk of loss for a low frequency, high severity event such as an earthquake or flood is not recommended.

Risk retention can take on several aspects. It can be as simple as establishing a reserve account for worker's compensation claims to as complex as reinsuring one's own captive insurance company with a separate finite risk contract. Accordingly, the retained portion of one's risk portfolio should at least have built-in protection for shock and/or batch losses.

Through careful analysis, peer studies, and some intelligent guesswork, insureds, brokers, and underwriters seek to apply the so-called law of large numbers and then determine a reasonable premium for transferring the risk in view of its own profit margins and the general competitive marketplace.

Insurers generally tend to spread their risk exposures over their numerous already insureds and where prudent attempt to protect themselves by transferring a portion of their risk to outsourced reinsurers. Insurers' interest in classes of risk such as CHP plant projects can vary with the short-term profitability of that class. A bad year combined with a less than impressive investment portfolio can often be enough to dramatically push a market out of a particular class.

Look for opportunities to renegotiate a policy should an insurer decide to buy market share on a short-term basis with below average pricing. An insurance company can also, on short notice, reverse itself and decide to drop out of the market because it failed to understand the risk on a subsequent or prior policy, failed to appreciate the exposure, and failed to accept the very long-term implications of CHP operational risks in periods of business downturns.

For most CHP plants, a combined risk retention-risk transfer strategy may be most cost-effective. Whatever the circumstances, one should seek to structure a program that is stable, cost-effective, and responsive to CHP plant operational issues and profitability.

In general, the risks associated with a private sector CHP project, falls into either a project- or non-project-related risks. Examples of non-project-related risks include adverse interest rates, unanticipated inflation adversely affecting financing, material, equipment or labor costs, changes to current codes, or adoption of costly regulations. Unfortunately the latter risks are not insurable using traditional insurer methods.

Project risks, however, are those directly related to the contemplated CHP project and can include, for example, loss to another CHP plant developer, unrealistic pricing of long-term utility power, failure to meet permit requirements, or business downturns affecting electricity demand.

Fortuitous risks, or those risks that happen by chance or accident are insurable subject to underwriting terms and conditions that ensure spread of risk and the elimination of moral hazard concerns. They include injuries to employees or third parties; delays in completing construction as agreed; physical losses or damage with the resultant loss of income or profits; related consequences of professional negligence; interruption to CHP plant operations; and major CHP plant equipment breakdowns.

Unfortunately there are no standard insurance and risk management programs for the on-site CHP plant industry. Understandably, a number of parties also have an interest in the risk management and insurance programs associated with a CHP plant project.

In addition to lenders and developers, the government, contractors, suppliers, and the public have legitimate insurable interests in a planned CHP plant project. During the life of the CHP plant project, these interest classes are likely change in importance and can result in divergent views. To adequately deal with those different interest classes that are likely to change, one needs to have the insurers focused coordination of the risk and insurance strategies and central purchasing of coverages and supporting services.

Financial interests in funding the design, construction, and resulting CHP plant operation often dictate the terms and rigidly enforce their compliance. Unfortunately, should significant gaps between the financial institution's expectations of eventual CHP plant profitability and those of the insurers regarding CHP project risk exist, failure to identify the so called expectation deficit can lead to serious problems later and their discussion is beyond the scope of this chapter but should be openly discussed among those interested parties prior to engaging an insurance carrier. Having CHP owner-operator contract professionals meet the underwriter to reduce the deductible waiting periods, substitute a financial deductible for a daily deductible, amend the indemnity measure to reflect the true loss, and/or extend the indemnity term beyond the outage period can be benefits worth discussing before policies are executed.

This discussion should involve the professionals negotiating the financing and power purchase contracts and the professionals negotiating the insurance and risk management contracts who will need to work closely together so that the balance of retained, assumed, and transferred risk referenced above is maintained. Power project insurance programs are generally arranged in two phases; namely:

Phase 1. Comprising the construction phase, including any testing and commissioning periods

Phase 2. Encompassing the CHP plant operating phase and which is generally reviewed on an annually renewable basis

An Overview and Limitation of Current Practice

When most contractors estimate construction costs for a proposed CHP project, they often look at past CHP projects as the database to be adjusted for future projects. Construction costs used in forecasting based on the analysis of only a small sample of historical in-house CHP projects with some form of cost breakdown, bearing some resemblance to the proposed new CHP project, becomes a natural starting point. However, where there are no past cost data available, experience and skill must play a role in collecting information to estimate yet unknown costs. Several factors interact and affect the reliability of the cost estimate including the extent of CHP design information available; the availability of in-house or published historical price data related to the CHP project under consideration; and the familiarity with constructing the proposed CHP project and/or other CHP projects of a similar scope and size.

Yet it is important to understand that CHP project costs used in any forecast can only be as good as the sample on which they are based. All else being equal, it is desirable that the sample should be as large as possible. Equally important is that the sample contains only related CHP construction projects closely resembling the proposed project. In other words, the sample should be reasonably homogeneous with respect to the major cost significant features of the proposed CHP project.

Significant improvement in reliability can only be obtained when historical price data are drawn from several completed CHP projects, even when sacrificing some comparability. Since the available database is finite, it often becomes a trade-off between sample size and homogeneity. Unfortunately, the precise nature of this trade-off is unknown, but as the uncertainties are high, a limited number of samples (for instance, fewer than five) are probably inadequate.

A word of caution is worth noting here. Often, cost data mask the impact of regional differences in construction prices and differences in size, quality, complexity, and constructibility of CHP plant projects. Professional skill and judgment is therefore needed in the careful selection of projects similar to the proposed project.

Dealing with Contractor Cost Uncertainties

In evaluating cost issues prior to undertaking actual construction either through competitive bidding, negotiating not-to-exceed or guaranteed maximum cost bids from a preselected group of qualified contractors or design-build firms, it is hardly ever the case where all activities experience either their best or worst line item cost during a given CHP plant project. The general result is a distribution of reasonably foreseeable CHP plant project construction costs falling in the range of actual costs most likely to be encountered. One approach used by many successful general or specialty contractors is to employ probability theory when considering three critical cost points: minimum cost, maximum cost, and most likely cost together with everything that goes on in between.

The process of selecting a probability distribution sometimes presents difficulties for the in-house construction risk manager. To choose the correct probability distribution, the following cautions are generally advised:

1. Be sure to list everything known about the variable sought including all applicable the conditions affecting the variable.
2. Seek to better understand the basic types of probability distributions and where they can best apply.
3. Be careful to choose the probability distribution that best characterizes the cost variable being sought.

Use of Probability Distributions

Distribution types which have been commonly used to evaluate probabilities of various data distributions under a variety of circumstances include Triangular, Uniform, Poisson, Normal, Exponential, Geometric, Hypergeometric, Lognormal, Beta, and Weibull. Distributions can either be continuous or discreet.

The most important factor in price forecasting is uncertainty. Cost estimation is more of an art than science since it involves both intuition and experienced judgment. There exists no objective test of the probability that a particular cost determination will result since it is the sum of many factors. Therefore an objective evaluation of its accuracy is possible only by the use of statistical techniques.

Probability theory allows future uncertainty to be expressed by a number, so that the uncertainty of different events may be directly compared. Information about the

probability of a future event occurring, or a condition existing, is generally presented in the form of a probability density function. If one can obtain some indication of the probability density function to which a particular price prediction belongs, there is a test of the likelihood that the estimate is unbiased.

Since it is beyond the scope of this chapter to give a comprehensive description of each of the above referenced distributions, references have been provided at the end of this chapter to familiarize one with clear explanations of most, including examples of their use and application when choosing the best distribution for a given analysis.

Three of the most commonly used distributions applicable to many of the cost issues related CHP plant construction referenced earlier are the uniform distribution, the triangular distribution, and the normal distributions.

1. In a uniform distribution, all values between the minimum and maximum are assumed equally likely to occur. For example, if no information about the existing utilities on the proposed CHP plant site is available, the value for any of the required connections can be assumed to be equally likely to occur. There are three conditions that must apply for the uniform distribution to be employed, namely, both the minimum and maximum values are fixed and all values between minimum and maximum are equally likely to occur.
2. The triangular distribution can be used to describe a situation where one desires to estimate the most likely value, where both the minimum and maximum values are known. However, values near the minimum and maximum value are less likely to occur than those values near the most likely. The triangular distribution is widely used in construction estimation due to its ease of use. A common drawback of the triangular distribution is that it is at best an approximation. Under some limited circumstances, however, the approximation may be worth the inherent benefits of using the triangular distribution method.

Triangular distribution construction is relatively simple to describe and a graphical solution can be found as follows. If one plots the probability density as the ordinate with the abscissa covering the range of probable values from minimum to maximum, one can plot a triangle, starting with the minimum value at the left end of the base of the triangle (also located at the abscissa), rising in a straight line to the right until an apex results then falling from the apex in a straight line until it intersects with abscissa at the maximum value thereby completing the triangle.

The most likely value can then be determined by extending a vertical line downward from the apex until it intersects the abscissa resulting in two right angle triangles where the ordinate is common to both. This graphical solution is based on the location of the intersection of the common ordinate with the most likely value found where it intersects the abscissa since the smaller area of the two right angle triangles represents the chance that the price will fall between the minimum and the most likely value.

3. The normal distribution can be considered the most important distribution in probability theory. The normal distribution is a family of distributions, each one shaped like a bell. The bell shape spreads outward and downward but never quite touches the horizontal scale. The distribution employs two parameters, the mean and standard deviation. Values are distributed symmetrically about

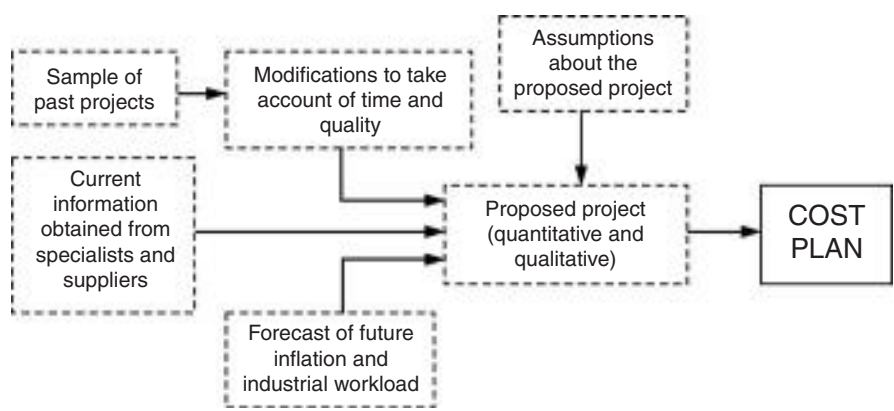


FIGURE 15-1 Cost planning process schematic.

the mean and as a result one has to have a reasonable idea about the variability of the data.

The normal distribution is most useful when one has a high level of confidence about the most likely price. The normal distribution uses the standard deviation, which has 68 percent of all values within 1 standard deviation either side of the mean. Accordingly, one's experience can be used that there is a 68 percent chance that the price will be within 1 standard deviation of the mean. A peaked distribution will have a smaller standard deviation and large standard deviation will have a lower, flatter top, and cover a broader area at its base. The bell-curve can also be asymmetrical (either to the right or left of the mean). This situation relates to the skewness of the distribution. Standard statistical measures can be used to cope with the skewness and a thorough discussion of its features can be found in the references discussed earlier.

A cost planning schematic is shown in Fig. 15-1.

Use of Risk Analysis to Establish Most Likely Cost

The cost A of construction work is a combination of what the client is either able or prepared to pay and the cost B at which the CHP plant contractor is prepared to undertake the work in order to show an acceptable level of profit. Accordingly, both costs (A and B) can be considered as residing in a community of costs, where there will be both extremes, for example, minimum or maximum and a most likely cost.

Prospective CHP plant owners generally assume that the budgetary construction cost estimates established at the completion of the CHP plant design stage represent the most likely cost. Yet they along with the proposing CHP plant contractor are also aware of the possibility that the actual resulting construction cost will either be exceeded or found below design completion stage cost forecast.

If budgetary CHP plant construction cost estimates are overly optimistic, prospective CHP plant owners waste valuable time and capital resources on construction documents that will have to be abandoned when contractor bids are received. On the other hand, overly conservative budgetary construction cost estimates produced at the

completion of design have the effect of discouraging investment in CHP plant construction and result in shifting investment in other more attractive energy conservation measures (ECM).

A further point to be considered is the interdependence of the elemental categories used in cost planning. Research has shown that certain elements will be interdependent, for instance the cost of the electrical installation is likely to be higher in a CHP project serving buildings with large computer and/or data center operations requiring extensive HVAC installations served from principally electrically powered centrifugal versus thermally powered absorption chillers.

Any risk analysis methodology must take account of interdependence related cost issues in addition to objective correlation coefficients requiring careful examination of the data which use historical data for construction cost planning. There are numerous different estimating techniques used at the design stage.

Some risk cannot be confidently estimated at the design stage, such as the effect on cost that exceptionally inclement weather will have on a project due to the foundation work commencing on site in early winter. Whereas the majority of risks arise from matters where there is a lack of information, for example, insufficient design and specification information at the early stages of design. As more information becomes available during the design phase, so many of the risks can be resolved until, just prior to a bid being sought, the estimate of construction cost contains only residual levels of risk.

A straightforward approach to including an allowance for the risk is to identify a list of risk items and assign each item with the probability of the event occurring and to give a three-point estimate of the lowest price, the highest price, and the most likely price.

For example, a typical risk item might be the probability of the need for a new gas main to be installed on site. At the design stage the existing gas main had not yet been exposed, hence its condition and size remained unknown. The most likely (common sense) line item cost might include an allowance for some modification to the existing main, whereas selecting the minimum line item cost assuming no work is required to the existing main, and the worst case, that substantial work is needed to modify the main, are equally less attractive. Accordingly probabilities for each event could be assigned to each event such that there is a 0.50 chance that some modifications are required, a 0.30 chance that no work is required and a 0.20 chance that substantial work will be needed. The assessment of probability can rarely be an exact science; therefore, expert judgment and intuition are required.

Consider next how best to estimate the most likely line item cost needed to adapt an existing natural gas line needed to supply fuel to a CHP plant prior to obtaining actual field conditions. There are again three possible scenarios for our CHP contractor's consideration:

1. Some modifications required to the existing on-site gas main
2. No modifications required to the existing on-site gas main other than inspection to determine points of connection
3. Substantial modifications required to the existing on-site gas main

As shown in Table 15-1, consideration must next be given to the cost to be allocated by the contractor for this element of construction cost. For the CHP contractor to include \$4900 which would cover both options (1) and (2) in his line item estimate can only be informed by looking at the fact that there is only a 0.20 probability that option (3) will be

No.	Item	Price (\$)	Probability	Allowance (\$)
1	Make modifications to existing gas main	8,000	0.50	4,000
2	No modifications: only inspection	3,000	0.30	900
3	Major modifications to gas main	23,000	0.20	4,600
Total				9,500

TABLE 15-1 Sample Allowance Calculation Based on Price and Probability

required and therefore the difference in cost between \$4900 to \$4600 amounts only to \$300. Therefore a mean cost of \$4750 would appear to be the most risk adverse line item cost.

Risk analysis generates hypothetical mean unit cost for each elemental category in the cost plan for the proposed CHP plant. These hypothetical unit costs are taken from probability distributions with the same statistical properties, that is, probability density functions, as those which characterize the original sample data from which the mean unit costs were estimated. The hypothetical rates are then used to build up a total construction cost forecast for the proposed CHP plant. If this exercise is repeated a sufficiently large number of times, it will be possible to obtain a picture of the probability density function which characterizes the total construction cost, and so to identify the most likely total construction cost.

This chapter has discussed elemental cost planning as the basis for illustrating risk analysis. It is equally applicable to other forms of prediction and estimating for building work where a sample of historical prices is being used. For example, forecasting the construction duration using activities and time using computer simulation with software, like Primavera, is frequently undertaken.

Use of Monte Carlo Simulation in Cost Planning

A more sophisticated available approach uses a process called *Monte Carlo simulation*, which uses historical data for a risk analysis of a cost plan. In this case, the decision maker uses the computer to generate the cost plan, having defined the distribution. A different approach would be for the decision maker to use experience, skill, and judgment to generate an estimate. Monte Carlo analysis proceeds by generating a series of simulations of a proposed project, each simulation giving a price prediction for the project. The predictions are plotted, first as a cumulative frequency curve and then as a histogram. There are several steps to the analysis; however, they are beyond the scope of this chapter.

Use of random numbers is also employed on occasion. Random numbers for computer modeling is a number generated between 0.0 and 1.0, which acts as a probability value, which in turn finds the value in the cumulative probability distribution corresponding to that probability value. Numbers chosen at random bear no relation to numbers appearing either before or after the sequence, but it must produce values in proportion to their chance of occurrence. The mechanics are governed by the shape of the probability distribution and the set of generated values will resemble the distribution that produced them. The usual approach is to use conventional Monte Carlo

sampling, but Latin Hypercube sampling is an alternative approach, where the probability distribution is divided into intervals of equal probability. The approach does provide increased accuracy at the expense of more computer time and memory requirements and is beyond the scope of this chapter.

Finally, one should be prepared to interpret the results carefully. Remember to look for any interdependence between the elemental categories. Contracting experience and intuition are required when employing Monte Carlo simulations. The strength of correlation between two variables will show the interdependence. Examine the shape of the resultant distribution and the cumulative frequency diagram. The cumulative frequency distribution allows one to examine the probability of obtaining a unit cost below a chosen unit cost. Basically, the distribution allows one to consider the chance of the most likely cost being achieved. Consider the statistics produced from the data, and, when possible, take the time to test the sensitivity of the data obtained and assumed by performing a sensitivity analysis on the key elements also used in the analysis.

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Operations

CHAPTER 16

Operation and Maintenance Services

CHAPTER 17

Sustaining Operational Efficiency
of a CHP System

CHAPTER 18

Sustaining CHP Operations

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Operation and Maintenance Services

Paul Howland

Plant Operators

CHP plant operators, who intimately understand the plant equipment, CHP systems, controls, modes of operation, and resultant impacts on overall efficiency, as well as emergency procedures, are key to successful, safe, sustainable CHP plant operations. CHP operators must be experienced and the exceptional operator knows that he or she must undergo regular training to stay up-to-date on changing technologies and regulatory issues.

Experience and Training

Plant operators have always been the key to reliable and efficient CHP plant operation. In several states and in large cities, a licensing program has been implemented which challenges plant operators on their knowledge of plant maintenance, operations, and safety, with the strongest emphasis on safety. Many employers require that the plant operators who are hired have a steam engineer license issued from the nearest city or state. Most insurance companies realize that casualties to equipment and personnel are greatly reduced when licensed operators are employed and have provided incentives to employers to hire them (if not outright required such licensing).

In the United States, licensing of steam engineers since the 1950s was focused on plants where steam was produced for district heating and cooling as well as for other industrial processes. Licensed plant operators were often trained in the navy or through apprenticeship programs, and upon completion of at least 4 years of training and experience would qualify to sit for the steam engineer license exam.

Historically, electricity was commonly produced using conventional boilers that were oil or coal fired to produce steam to drive turbine generators. These plants were typically owned and operated by utility companies. The utility companies are either investor owned or run by municipalities. The utility companies have their own internal training programs, developing several levels of competency with associated job titles specific to the power industry. As a result they did not require or recognize a steam

engineer license issued by a city or state as requirement for employment. As in the case of district heating and cooling plants, many of these utility engineers received their basic training in the navy, where engine technology and plant systems aboard a ship is commonplace.

Beginning in the 1980s manufacturing facilities became aware of the development of small combustion turbine-driven as well as reciprocating engine-driven generator packages and changed the way their plant operators performed their jobs. Now with the higher cost of electricity purchased from utility companies, the use of reciprocating engines and combustion turbine technology (as well as other CHP technologies) has spread to district heating and cooling operations of all sizes. Now we have steam engineers who are no longer firing conventional boilers to produce their process steam. The steam engineers are challenged to learn about various engine packages, heat recovery, the production and distribution of high voltage and how to maintain an efficient balance of process steam or hot water produced as the result of power production.

Even as technology and demands for steam and electricity change, qualified plant operators are still in demand. From hand-positioned controls to microprocessor-based control systems, the plant operators today and into the future will need to receive additional training in the use of the new tools now at his or her disposal. However, the bottom line is that these operators are still responsible for mechanical rotating equipment and there is no substitute for the human senses in the day-to-day operation of the plant.

Each operator brings their individual skills and abilities to their plant. Those skills and abilities should be recognized and encouraged by plant management. Those individual skills such as welding, pipe fitting, and instrument calibration are in addition to the ability of each operator to use all of their respective senses to constantly analyze the present and changing conditions of the plant. Operators need to understand the internal workings of individual pieces of equipment, how individual pieces of equipment are connected and controlled as CHP plant systems, and how the individual CHP plant systems work together to provide an efficient, functioning CHP plant.

The Exceptional Operator

The most common way that an operator recognizes the conditions of the plant is visually. Every plant monitors pressures, temperatures, levels, and flows through the use of instrumentation and commonly presents that information via a gauge, chart, or computer display. The operator can see the data displayed and may determine from the data if the plant is running properly and efficiently. Through the use of computer programmed monitoring and human-machine interface (HMI) software and monitor screen displays the operator can see the data organized graphically to represent the process flow of the plant and observe on/off status of equipment as well as warning and alarm conditions. The operator will also be able to visualize the interaction of processes as parameters change and gain new insights. The plant computer can archive the hundreds of process measurements as historic data files and provide the operator with the opportunity to build graphs and charts to further analyze trends and the performance of the plant (see Chap. 17).

An exceptional operator will use his or her other senses too. The plant is not just a noisy place that usually requires hearing protection. There are sounds in the plant that the exceptional operator has learned to recognize. For example, the operator listens to the sound of a feed pump or a condensate pump; the operator listens to the sound of the

steam turbine generator (STG) or the sound of the combustion turbine generator (CTG) to name a few examples. The operator listens to the sounds of the equipment when it is running properly and can detect those individual signature sounds (e.g., frequencies and pitch) along with a heightened awareness when those sounds suddenly change as a precursor of potential problem operating or impending failure conditions. An exceptional operator can walk into a plant at the beginning of the shift and hear a different pitch or frequency within the plant and have cause for further investigation.

There are also vibrations in a plant that can be felt if an operator is focused. The exceptional operator will feel the vibration of the plant through his or her feet as they walk or stand in different places and will feel vibrations with their hands as they touch pieces of equipment. Of course, there are some vibrations that are too small for the operator to sense and in those cases very sensitive equipment is used to measure vibration or movement in a millionth of an inch (mils), for example.

The exceptional operator will also use all of their senses and the tools provided through the computer to determine if the plant is running properly or if there is a very small and easily correctable problem to be addressed before it becomes a large problem that requires unscheduled down time or worse, a catastrophic failure of equipment and/or harm to personnel. At this point, any knowledge gained from this exceptional operator is only valuable when is shared with the other operators and with management. Open communication must be encouraged and cultivated by plant management to allow an atmosphere where all information for anyone in the organization is accepted and treated as valued input even though it may not prove out in some situations following investigation.

Exceptional operators are often promoted to supervisory and management positions as they acquire leadership skills on top of their learned technical skills. Accordingly, the plant supervisor or manager to whom the operator reports and who may expect future promotion should be encouraged to act proactively to provide training, to mentor and guide new operators in promoting their skill sets, and to be positive reinforcement to assist in their development into exceptional operators.

Plant Inspection

At the beginning of each shift, the plant operator must be encouraged to take the time needed to thoroughly inspect the plant. The operator should look at each piece of equipment that is online and make a quick assessment of its current condition. The operator should also look at the condition or readiness of any equipment that is on standby status. This inspection entails, for example, looking at pressure and temperature gages, flow meters, and level indicators. The operator should check all motor-driven pumps and fans by placing a hand on motor housings to check bearing temperature and also to feel for excess vibrations. Cooling towers should also be inspected, looking at water flow, level and temperatures, and for debris at the air inlets. Lubrication systems must be inspected to ensure proper pressure and flow and to verify by looking at the sight glass that the oil is at the proper level and is not contaminated.

After this initial inspection, the operator will usually go to the control room to verify what he or she observed during the plant walk-through. The plant logs should also be carefully reviewed to gain a better understanding of what has taken place on the previous shift and if further follow-up is indicated. The operator should be required to look at the screen displays on the HMI to document any unusual findings and observations made before his assigned shift in the plant. Lastly, the operator coming on shift

will discuss the plant with the operator just completing the shift and ask any questions when appropriate to help clarify the visual inspection made in the plant when he begins his new shift. This will help ensure a good plant turnover.

Emissions Control

Environmental concerns have also grown in recent years since both district heating and CHP plants are subject to more stringent regulations intended to reduce harmful emissions from the plant into the atmosphere. As noted in Chap. 14, the operator must be trained to recognize the limitations imposed on the plant, know how to recognize when an emissions limit is about to be compromised, and know how best to respond in a timely manner to prevent the excursion from taking place on his watch.

As discussed in previous chapters, the emissions from a CHP plant are strictly regulated in many parts of the country and around the world. Operators must monitor exhaust stack emissions and understand the mandated maximum allowable emission rates. With natural gas-fired CTGs, carbon monoxide (CO) level should be low, indicating complete combustion, along with nitrous oxides (NO_x) which should be maintained as low as possible. If the CTG is fired on liquid fuel, usually diesel, then sulfur dioxide (SO₂) should also be monitored. There must also be concerns over particulate matter (PM) emissions along with ammonia slip where selective catalytic reduction (SCR) is employed to reduce NO_x levels discharged to the atmosphere.

Health and Safety

A health and safety program is essential at all operating CHP plants. Each operator must be encouraged to become serious about protecting his or her health as well as those working around him by using the proper safety procedures, wearing the proper clothing, and attending all required safety training sessions. A serious lost time injury to an operator can have devastating consequences to that individual as well as affecting the productivity of other plant personnel.

One of the most important aspects of safety in a CHP operation is lock-out-tag-out (LOTO) procedures. A CHP operator must not have the opportunity to accidentally start a piece of equipment when it is being worked on by others. Everyone working in the plant (including contractors) must strictly follow the mandatory LOTO procedures to help ensure that there is no chance that a circuit can be electrically energized, or a steam or hot water valve accidentally opened or shut that could lead to injury and/or death of his fellow workers.

There are numerous potentially harmful chemicals used in CHP plants to treat water systems. Generally, these chemicals are employed for biological growth control and corrosion inhibition. Each operator must be aware of what safety equipment to use when handling any chemical spill and they must read and be familiar with the material safety data sheet (MSDS) for each specific chemical, and must know what steps to take if they accidentally released or are exposed to hazardous materials due to inadvertent actions or failure to follow prescribed procedures by others.

Written Guidelines and Procedures

Most well-run CHP plant operators have received training or provided with written standards that they are trained to observe and required to follow in the event emergency plant operating conditions occur without prior warning or notice. Since there is no way to

anticipate every situation, a set of guidelines and procedures are written in a manner to provide operators with a basic understanding of their responsibilities, information needed to undertake specific tasks, along with some generalities and expected outcomes. In some cases, the guidelines will change based on seasonal load patterns. The guidelines are intended to suggest the selection of equipment available to address the load and at the same time seek to optimize system efficiency wherever possible. In a CHP plant, it is important that the plant operators have a number of options where the steam or hot water produced in the heat recovery steam generator (HRSG) or heat recovery hot water heat exchanger can either be fully used or shifted to when electric loads change.

It is important to allow operators some slack to make decisions based on observed conditions, but within guidelines established by management, to ensure that the plant is not allowed to operate in an inefficient manner. Exceptional operators will, at times, find methods that will result in changes to prescribed written procedures or guidelines. Such exceptions must be carefully documented and approved by management only after proven to be repeatable prior to being written as exceptions into the procedures manual to avoid misuse.

Plant Start-Up

Black Start

In many CHP plants, the power that is produced is distributed in a parallel configuration with the local utility power to meet the facility load. The total load requirement may exceed the capacity of the CHP plant and the facility must rely on the utility power to provide the balance of required electric power. It is not uncommon for the utility power sometimes to go down (i.e., for a blackout to occur) due to an act of nature, an overload condition, or equipment failure. When this occurs, it is likely that the CTG or engine-generator will trip off as well due to voltage disruptions. The facility is now without power or “black.” The plant operators must try to get power back to the facility as soon as possible. A black start generator is necessary in this situation, or the plant operators must wait until the utility power is restored. In some facilities, an automated load-shed program may prevent the generator from tripping on an overload condition when utility power is suddenly lost.

A diesel engine generator is commonly used for black start. The plant operators must first open the circuit breaker to the utility supply to “island” the facility (i.e., disconnect the facility from the utility power grid). The facility, if large enough should have a load-shed plan so the CHP plant can always be started in a balanced load condition. If the breakers are not automated, the plant operators must be instructed to manually open the breakers to remove load. The black start generator is usually designed to provide just enough power to the auxiliary loads that are required to support the start up of the CHP plant. For example, the auxiliary loads should be capable of supporting the CTG and the associated HRSG under emergency conditions.

In addition to the auxiliary loads, the black start generator provides a voltage and frequency that the CHP prime mover can read and be synchronized with. Once the engine is rolling and has completed its warm-up cycle, the plant operator will bring the engine up to operating RPM and then bring the generator online. The generator frequency must be synchronized to the line frequency. The plant operator usually has the option to initiate synchronization with an automated control or in a manual mode. In

manual mode, the plant operator watches a dial with a rotating pointer. The pointer will rotate passing zero at the top of the dial. Zero on the dial indicates when the frequency of the generator and the line are equal. There are usually two lights located above the dial that light up when the pointer is at or within a few degrees of zero. The plant operator uses a knob below the dial to slow the rotation of the pointer. When the pointer is rotating very slowly and it reaches zero on the dial, the operator will turn a switch which then locks in the frequency of the generator with the line frequency. It should be noted that on most control systems, if the operator turns the switch when the frequency is not in sync and the pointer is not at the zero point on the dial the control system will not allow the generator to attempt a frequency lock and problems will persist until corrected.

Bootstrapping

In power plants, bootstrapping refers to methods for black starting a main generator. In large utility plants, there may be a diesel engine generator which allows a small CTG to start and synchronize to the diesel generator to provide enough power to start the main generator. In a combined cycle plant, a diesel engine generator may allow a standby boiler to be fired which supplies steam to the STG. The STG would then be paralleled to the diesel generator to provide enough power to a CTG. In many cases bootstrapping will allow for a smaller, more economical diesel engine generator to be utilized.

Restart

Each time the CTG or engine-generator is shutdown or trips off unexpectedly the prime mover equipment and the internals in the HRSG (or hot water heat recovery unit) are subjected to thermal stress. This is true for both shutdown and start-up operation. The plant operator must wait for the unit to go through a warm-up cycle after a start is initiated. If the engine or CTG trips off, the plant operator must quickly assess whether there is a serious problem that will cause the unit to be down for an extended period. The engine will require a rolldown period that is programmed into the control system. The rolldown period may be 10 minutes or longer depending on the size of the unit. If the reason for the trip can be reset quickly, the plant operator can gain a permissive to initiate a restart without further delay. If the CTG or engine generator is down for an extended period, the warm-up cycle will take at least an hour and sometimes much longer depending on the plant size and on how long equipments/systems have been off.

Decisions on Plant Optimization

Plant optimization opportunities depend on a number of factors including CHP electric and thermal capacity versus facility loads; the various plant production and use options for electricity, heating, and cooling; the level and sophistication of plant metering, monitoring, and controls; the data and analysis available (see Chap. 17); and the knowledge and experience of the plant operators. For example, if a CHP has been designed and constructed to be fully base loaded thermally and electrically all of the time, then there are no decisions on plant optimization, as compared to CHP plant that needs to be adjusted to varying electrical and thermal loads. On the other hand, for example, a combined cycle CHP plant with duct firing can adjust the amount of steam production and power produced in an STG. The more computer-tabulated and displayed metering and monitoring that a CHP possesses, the easier it is to understand and optimize a CHP plant (see Chaps. 17 and 18).

CTG and STG Optimization

Optimizing the performance of a CHP plant can be a constant challenge for the plant operator. The plant design should provide for the ability to use all of the steam or hot water produced in the heat recovery unit as the electric load changes so that engine turndown is minimized. Note that typically if there is an opportunity to provide steam from the HRSG to processes or thermal loads, the most efficiency is gained serving those processes or thermal loads first, although greater value may be obtained from a power-production-first strategy.

Heat recovered in the form of steam or hot water can also be used for thermal-powered cooling. In a combined cycle plant, additional steam may be used to drive the STG if there is a demand for additional electricity. The CHP plant will typically operate at the highest efficiency when the STG is allowed to follow the steam availability, varying the electricity output. If additional electricity is needed and the STG is not at full load, more steam can be directed to the STG via supplemental duct fire, also known as firing the duct burner.

Duct Burner

The duct burner has the potential to enhance the performance of a CHP plant by greatly increasing the output of steam from the HRSG by means of supplemental duct fire. The plant operator must monitor and control the amount of steam produced with the duct burner and be able to determine when plant conditions are appropriate for the use of duct burner firing so as to optimize plant operation. The cost of the fuel used for supplemental duct fire can be offset by a measurable increase in plant efficiency. The plant operator should have the necessary efficiency data at the control console to enable his decision in any event.

Inlet-Air Cooling

A more direct enhancement to the efficient operation of a CTG is through inlet-air cooling particularly during seasonal warmer outdoor conditions. The plant operator will be required to closely monitor the CTG performance and adjust the set point of the inlet-air temperature control to boost the output of the generator to improve toward International Organization for Standardization (ISO) conditions. This is usually necessary during a hot and humid afternoon when the electric load is at its highest. The inlet-air cooling process can also extract the excess moisture from the air (if cooling coils are used), to enhance performance of the combustion turbine engine.

Balance of Plant

In a combined cycle plant, the steam produced in the HRSG is often directed, as a first priority to plant thermal loads or processes. The plant operator must continually monitor all of the loads in the plant and determine the most efficient way to address the loads. He or she must always have an awareness of the overall balance of the plant and how individual equipment performance and weather create imbalances.

In a district heating and cooling plant with CHP, the heating and cooling load variations will require operators to seek a balance of the CHP prime movers, STGs, thermal chillers, and building heat production. The more diverse the plant design is the more opportunities the plant operator has to maximize efficiency as loads change. For example, the plant operator should be able to select either electric- or steam-driven chillers to deliver building cooling. In many CHP designs, absorption chillers are used to produce

chilled water. Absorption chillers generally use large volumes of steam at relatively low pressures to provide a constant supply of chilled water.

In many cases, as the building heat loads decrease, the cooling loads increase. These are ideal conditions, which, for example, will allow the plant operator to shift the flow of steam from the building heat to steam-driven centrifugal or absorption chillers, or to steam-assisted power auxiliaries, for example, fans and pumps where installed. There are also cases where, during a hot humid afternoon, the electric load is at a maximum level and all most of the steam would be better directed to the STG to provide more electricity production.

Computer Data Logs

Microprocessor-based monitoring and control systems are normally distributed throughout the plant. They are designed and programmed to provide plant control through set points as well as process and safety limits for all major pieces of equipment in the plant. Computers with graphic displays sometimes called HMI. The HMI takes data from the control system and provides process information and points of control for the plant operator. The HMI also provides an opportunity for the plant operators or management to produce both historic data and real-time data.

Data logs can be generated in various formats such as graphs, bar charts, and tables. The information about plant performance and efficiency can be gathered in the computer and displayed in a manner that is easily understood. The plant operators should be able to equate their decisions and actions while operating the plant to the outcomes displayed, and be able to make adjustments and see the results over a short period of time.

Plant Maintenance

CTG

Most maintenance on a CTG or reciprocating engine requires a shutdown and the work often requires the expertise of factory-trained and experienced mechanics. The plant operator has a responsibility to be aware of any changes in plant readings. The operator must be on the alert for any unusual operating conditions that may be indicated by changes in vibration or noise.

One of the most important responsibilities of the plant operator is to inspect and maintain the integrity of the lube oil system. The condition of the lube oil can be visually checked for color and flow and level in the storage tank. Lube oil temperature and differential pressure at the filters should be monitored and alarmed in the control system.

Keeping a CTG clean will provide the best opportunity to maximize its efficiency over time. The inlet filters must be monitored and changed as often as necessary to prevent excessive pressure drops which degrade CTG performance. Even the best filters will not prevent a CTG from getting dirty. Some turbines have an option to water wash while the turbine is running rather than requiring a shutdown.

HRSG

The heat recovery steam generator is basically an unfired water-tube boiler. The HRSG is specifically designed to generate saturated steam from the CTG engine exhaust gas.

The HRSG may also have a separate superheater section and an economizer. Like any boiler, it is very important to maintain a reliable water conditioning system to control scale build up. The CHP plant operators must test and chemically treat the HRSG water on a daily basis.

Further, like any boiler, the HRSG must be opened for cleaning and inspection once a year. There are many installations where air quality regulations require a significant reduction in exhaust emissions. In these cases, catalysts are often installed in the HRSG. The catalyst sections should be visually inspected and a section should be removed and tested in a laboratory to determine the remaining service life. The NO_x catalyst requires ammonia injection and the delivery and injection system must be cleaned and inspected periodically.

STG

In addition to the schedule in Table 16-1, the steam turbine internals must also be inspected periodically. The frequency of the inspection depends on the steam conditions and operation, but, if possible, should not exceed 3 years (see Table 16-2). It is important to check the lube oil system for proper level and quality before starting the unit and while it is in operation.

Steam Turbine Chillers and Absorption Chillers

Maintenance requirements on steam turbine-driven centrifugal chillers are identical to the STG on the turbine side. The chiller end must be leak checked and maintained with the proper amount of refrigerant. The evaporator and condenser heat exchangers must be cleaned and inspected at least once a year. Condensing water must be provided and maintained at the proper temperature to achieve the overall efficiency of the chiller. If a cooling tower is used, the operator must maintain an effective water conditioning and chemical treatment program to protect the condenser tubes from fouling and corrosion.

Maintaining absorption chillers is unique in that it has no internal moving parts. A constant flow of water through the evaporator and through the condenser will maintain a stable heat transfer process within the unit. Since steam or hot water is used to separate the water and lithium bromide in the generator section, the heat transfer in the condenser is greater than with centrifugal units, therefore the cooling water supply is even more important.

Plant Auxiliaries

A CHP plant has a number of auxiliary systems that support the CTG, engines, generators, and HRSG, or hot water heat recovery unit. Most of the equipment is common to

Maintenance
Annual permit inspection
Open all ducts—inspect, for loose insulation, all internal panels, catalyst and clean
Drain and open mud and steam drums and clean
Replace safeties (send out existing for recertification)

TABLE 16-1 Typical HRSG Maintenance Schedule

Maintenance	Daily	Monthly	Qtrly	Semi-Annual	Annual
Check the over-speed trip by accelerating the turbine to trip speed		X			
Clean all linkage systems and inspect for wear			X		
Clean and oil or grease all the moving parts (fulcrum points)			X		
Remove and inspect bearings				X	
Inspect radial contact surfaces (journal)				X	
Inspect axial contact surface (thrust faces)				X	
Make sure no signs of overheating, excessive wear, including dents, grooves, tears, or dirt				X	
Check the effectiveness of all drains				X	
Disconnect and separate couplings. Remove all grease and sludge and then flush. Inspect wear on the hub and cover teeth. Then dry and replenish with new, high-quality grease				X	
Check the sentinel and relief valves to ensure they are operational. The relief valve should start opening when the sentinel valve opens and should completely open when the pressure in the casing is 10% above normal pressure				X	
Operate turbine without a load and inspect governor operation and vibration				X	
Drain governor's oil, if applicable, while it is hot; flush governor and replace oil					X
Remove and clean governor valve and internal steam strainer. Check for leaks					X
Send oil sample out for analysis					X
Replace oil filters					
The turbine internals must be periodically inspected. The frequency of inspection depends on steam conditions and operation but should not exceed 3 years					3 years

TABLE 16-2 Typical STG Maintenance Schedule

both CHP and district heating and cooling plants such as feed pumps, deaerating (DA) feed tanks, condensate pumps, condensers, and cooling towers. Cleaning and general maintenance on these equipments is relatively standard and well understood, but is quite important in maintaining the CHP plant at its highest operational efficiency.

Other auxiliary systems in CHP plants are specialized and require special training to perform either scheduled or breakdown maintenance on those systems. One example

is ammonia injection systems for NO_x reduction. When CHP plants are near public areas, urea is often delivered and stored in lieu of ammonia itself. The urea is pumped from the storage area and heated to be converted to ammonia just before it is injected before the SCR unit. The delivery pipe, pump, and heater must be kept clean and must be flushed with distilled water to prevent a urea build up that would eventually plug the injection pipe and cause NO_x emissions to exceed limits.

A second example is natural gas compressors. Many CTGs operate on natural gas or other combustible gasses that require higher pressures than are available at the gas main. The gas compressor boosts the gas pressure to the point that it will enter the CTG. The gas compressor system incorporates filters that also require regular inspection and cleaning.

Another specialized system is the emissions monitor system, where stack gas is sampled and analyzed on a continuous basis (CEMS). The CEMS must be calibrated periodically as stated in the “permit to operate.” Any service required beyond standard calibration should be performed by factory-trained technicians.

Down Time Planning

Down time planning to accomplish maintenance requirements can be a difficult task, especially for facilities that demand 24/7 operation. Plant management must identify times throughout the year, where the impact will be minimal to the mission of the organization to which the CHP supports. The biggest impact will be the increased costs of electricity. In many cases the local utility will impose a costly standby charge whenever the in-house generation goes off line.

Whenever the CTG is scheduled to be down for maintenance, all related equipment will be down and should also be scheduled for maintenance. This maintenance outage must be carefully planned to ensure that outside contractors are appropriately scheduled well in advance and that all spare parts that would possibly be required are on site. Factory maintenance contracts help to simplify the process with parts, labor, and expertise.

CHP and the Plant Operator

A CHP design can provide projections of efficiencies that impress all of the stakeholders, producing the funding and focus to build the facility or expand an existing facility. After the plant is constructed and commissioned, plant operations must take over and demonstrate that the design meets or exceeds the performance projections. This chapter has outlined the importance of the exceptional operator as an individual and as a member of the operations team and should be recognized as a key factor in the overall success of any sustainable CHP operation.

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Sustaining Operational Efficiency of a CHP System

Srinivas Katipamula

Michael R. Brambley

This chapter is intended to provide background information on why sustaining operations of CHP is important. It also provides the algorithms for CHP system performance monitoring and commissioning verification (CxV). The latter process starts by presenting system-level and component-level performance metrics, followed by descriptions of algorithms for performance monitoring and CxV, using the metrics presented earlier in the chapter.

Verification of commissioning is accomplished by comparing actual measured performance to benchmarks for performance provided by the system integrator and/or component manufacturers. The results of these comparisons are then automatically interpreted to provide conclusions as to whether or not the CHP system and its components have been properly commissioned, and where problems are found, guidance for correcting problems. The use of these algorithms is then illustrated by applying them to CHP laboratory and field data. The chapter concludes with a discussion on how these algorithms can be applied in the real world.

Background

Although recent technology advancements have made building-scale CHP a more viable option, there are several challenges that need to be overcome before CHP technologies are universally adopted in the commercial buildings sector. Because they rely on interactions among systems, CHP technologies are more complex than existing building systems. Unless the various components of these systems work as an integrated unit, their full operating potential as well as their full market penetration potential will not be realized, and could be damaged if early installations encounter operation problems. Integration of CHP technologies with existing building systems brings additional challenges that need to be addressed as well. Finally, many commercial buildings lack adequate control infrastructure, building staff trained to operate CHP systems, and proven operations and maintenance practices for reliable and optimal operation of these systems.

Given the poor current state of operations in many commercial buildings, integrating distributed generation (DG) technologies with existing building systems presents a challenge. Although no reliable nationwide estimates are available, many case studies in limited geographic regions over the past decade or more have shown that a significant fraction (as much as 30 percent) of the energy consumed in commercial buildings is unnecessarily wasted (Ardehali et al. 2003; Ardehali and Smith 2002; Claridge et al. 2000, 1996, and 1994). Much of the waste can be related to the inability to control and maintain building systems, and detect, diagnose, and correct operational problems when they occur.

The emergent CHP industry must face the challenge to reliably integrate controls for the various CHP components to maximize system efficiency, optimize system performance, prevent damage to equipment, and integrate CHP with existing building controls. As discussed in previous chapters, CHP components are available in various sizes and models from various manufacturers. Engineers, contractors, and integrators assemble these components into integrated packages where capacities and operation match those of individual building load profiles. The capability to assemble controls for these systems automatically and error-free in a plug-and-play manner, with embedded diagnostic capabilities, would provide a huge advantage to this new technology entering the buildings market.

For CHP technologies to work at near-optimal and fault-free conditions, facilities as well as CHP plants need supervisory control systems that coordinate the operation of the entire CHP asset and integrate the CHP system with existing building systems. Challenges in integrating CHP systems with existing building systems include sizing the equipment and systems to optimally match the building's requirements; smooth and seamless interface between CHP controls and existing building controls; regular and frequent assessment of building loads (electric and thermal) as well as equipment and system performance; and coordination of building demands and grid needs to match CHP system outputs and to determine how much and when to throttle back the CHP system or to sell power back to the grid. Many buildings lack a control infrastructure suitable for seamless integration of a CHP system with existing facility systems.

Why Supervisory Controls and Diagnostics Are Relevant

The key challenge facing the emergent CHP technologies is the integration and bundling of today's unitary equipment into turnkey packages where components are sized and controlled for optimal performance for a specific building's energy usage profile. This suggests that suppliers will assemble CHP packages from various types and sizes of components from original equipment manufacturers (OEMs) and provide the associated controls and control strategies, so that the heating, cooling, and electrical outputs of the package can be matched to the building loads as they change from hour to hour and season to season.

Realizing the potential energy savings and societal benefits from CHP will require its rapid acceptance and penetration into the buildings sector. To accomplish this, suppliers must produce flexible, integrated systems quickly, inexpensively, and reliably, while honoring the OEMs' suggested ranges and absolute limits for equipment operating conditions. Therefore, there is as great a need for plug-and-play controls as there is for physical compatibility among equipment.

Ensuring a high level of performance that will guarantee continued consumer acceptance requires continuous, on board performance diagnostics for both component-level

faults and degradation of the overall system performance. Equipment-level diagnostics from different OEMs may need to be integrated to achieve system-level diagnostics.

Supervisory control and automated diagnostic algorithms can be the basis for automated tools that help the building engineer, building manager, or energy service provider better manage complex CHP systems and their interactions with existing building systems. Three major functional requirements for such supervisory controls and diagnostics are

1. Provide continuous feedback to operators on system performance using easily understood performance metrics
2. Automatically detect, diagnose, and project system and equipment degradation and faults using algorithms for automated fault detection, diagnostics, and prognostics for components and systems
3. Provide support for optimization and load balancing using adaptive predictive controls and automated decision support tools

Continuous Performance Feedback

Although providing performance feedback to operators or energy service providers managing CHP systems will not guarantee optimal operations, it will provide the performance information that will enable operators to recognize anomalous situations requiring action. The proactive operator will use this information to notice plant changes, investigate them, and make necessary corrections and operational changes.

Automated Diagnostics and Prognostics

Automated fault detection and diagnosis (AFDD) is an automatic process by which faulty operation, degraded performance, and failed components in a physical system are detected, understood, and reported. AFDD tools are based on algorithms that process data to determine whether the source of the data is experiencing a fault. For more details on AFDD methods for building systems refer to Katipamula and Brambley (2005a and 2005b).

The AFDD tool may be either passive, analyzing operation of the equipment/system as it operates, without altering any of its set points or control outputs, or active, automatically initiating changes to produce or simulate operating conditions that cover a wider range of conditions that might be experienced for a considerable time under normal operation.

Even if the integrated system is commissioned during installation, this does not ensure continued proper operation. Only continuous monitoring of the status of the equipment and its performance and correction of faults can ensure continued proper operation. AFDD systems are central to this continuous monitoring and commissioning process by constantly monitoring equipment and identifying faults or degradation in performance. Further, prognostic tools can inform operators and maintenance personnel regarding the time before failure or significant performance degradation, enabling personnel to anticipate and plan for maintenance. The human operator or repair person is still critical to completing the commissioning and maintenance cycles, but without continuous, automated systems monitoring, problems can go undetected for days, weeks, months, or even years and none can be anticipated in advance.

The functional types of diagnostic algorithms needed are

- *Component-level diagnostics.* Diagnostic algorithms that monitor component performance on a continuous basis to detect and diagnose faults in system components.
- *System-level diagnostics.* Even if individual components are operating properly, the system as a whole may not be operating optimally. Therefore, there is a need for diagnostic algorithms that monitor whole-system performance on a continuous basis and detect and diagnose faulty and degraded operation.
- *Building integration diagnostics.* Because the thermal output of CHP systems is integrated with existing chilled and hot water distribution loops, there is a need to optimize the performance of the integrated system.
- *Prognostics.* These tools are needed to enable operation and maintenance personnel to anticipate and plan for repair and maintenance to maintain performance and minimize downtime.

Performance Monitoring

This section explains the purpose of and a general approach to performance monitoring and commissioning verification. This section also specifies the equations for performance monitoring of all components of the generic CHP system. The components can be combined in various ways to create CHP systems and, therefore, these algorithms can be used to monitor the components of many different CHP system configurations.

The performance of CHP systems can be categorized according to the outcome of primary interest. CHP systems have the objective of providing both electric power and useful heat at the lowest cost possible, while meeting other requirements such as constraints on environmental emissions. Once the physical system is designed and built, operating costs can be controlled by maintaining efficient operation (maintain to sustain). This involves both operating the system well (ideally optimally) and maintaining the system so that it can perform efficiently. Efficiency should be maximized to minimize fuel use (and fuel cost) subject to meeting (but not exceeding) facility loads. Of course, this must be balanced against the cost of each additional maintenance activity.

The algorithms, when implemented in a tool, provide information to CHP system operators so they can initially ensure that the performance of their CHP systems and their individual components meet performance expectations established by the project engineer or manufacturer(s) (through CxV) and then monitor performance to quickly spot degradations in efficiency sufficient to warrant changes in operation or maintenance action. Performance monitoring can then serve as the basis for corrections to operation and initiation of maintenance (i.e., *condition-based operation and maintenance*).

To enable operators to track CHP system performance and detect problems, algorithms are provided for monitoring the performance of the overall CHP system and the efficiency of each individual component. The overall efficiency is an indicator of how well the system is converting fuel into electricity and useful heat. Significant degradations in system efficiency indicate both a loss in the capacity to generate these useful forms of energy and an increase in fuel use per unit of useful output energy. The latter would lead to increased fuel costs.

The fuel utilization efficiency (η_F), can be defined as

$$\eta_F = \frac{\left(W_{\text{elec}} + \sum_j Q_{\text{th},j} \right)}{Q_{\text{Fuel}}} \quad (17-1)$$

a metric for overall CHP system performance. Here, W_{elec} is the net electrical power output, $Q_{\text{th},j}$ represents the net rate of useful thermal energy output from heat recovery process j with the sum being over all thermal recovery processes in the system, and Q_{Fuel} is the total rate of input of fuel energy to the CHP system. This is the most commonly used indicator of CHP system efficiency, although as noted in Katipamula and Brambley (2006), it fails to account for the quality (exergy) of the different energy streams. Equation (17-1) is specialized to a specific CHP system configuration later in this chapter. To account for the quality of the various energy streams, we also use the value-weighted energy utilization factor (EUF_{vw}), which is discussed in more detail later in this chapter and in Katipamula and Brambley (2006).

The generic components of CHP systems include combustion turbines, microturbines, or reciprocating engines as prime movers; electric generators; heat recovery units (which are heat exchangers); steam turbine-driven centrifugal chillers or absorption chillers (which convert waste heat from the prime mover to useful chilled water for cooling); supplemental electric-drive vapor compression chillers to help meet cooling loads during times when the thermal-powered chiller cannot or does not meet the entire load;* cooling towers; desiccant systems for dehumidifying air; and pumps for moving liquid and fans for moving air.

Commissioning Verification

Commissioning verification (CxV) is a process by which the actual performance of the individual components in a CHP system and the performance of the CHP system as a whole are verified to comply with the designers' and manufacturers' specified performance. Furthermore, for new systems, commissioning should include a systematic series of activities, starting in the planning phase and continuing through design, installation, and start-up, aimed at ensuring that the owner's project requirements are met and the CHP system operates correctly. Before start-up, the process should include inspection and testing of all components in the CHP system to ensure proper components are installed, they are installed correctly, and they perform properly.

Another goal of this chapter is to provide the reader with algorithms that can be used to automate parts of the process for verifying that commissioning has been done correctly and resulted in a CHP system that meets design and operational expectations. Although CxV can include active testing of *components* and *subsystems*, this chapter focuses on verifying performance to ensure that the *system* has been adequately commissioned and to provide indicators of commissioning still needed when deficiencies are found.

*Vapor compression chillers used for this purpose often are not considered part of the CHP system, but because use of thermally powered chilling must be optimized as part of a larger system that includes vapor compression chilling, they must be included in decisions made by the supervisory controller regarding how much thermally powered chilling and how much vapor compression chilling to use to meet the total cooling load.

This process relies on the monitoring algorithms described next. The CxV algorithms provide the logic by which measurements on performance are interpreted, relative to performance expectations, to identify during initial operation of the CHP system deficiencies in the performance of the system and major individual components. By verifying the performance of the individual components, deficiencies in overall system performance can be isolated so that follow-up efforts can be targeted at the offending components. Some deficiencies may span multiple components of the system. In these cases, controls for component integration are identified as needing rechecking and further commissioning. The outputs of the CxV algorithms are alarms, quantitative indicators of deficiencies, and supporting information to help guide corrective actions.

Component Monitoring

CHP system components can be combined in various ways to create CHP systems (see Fig. 1-2) and, therefore, these algorithms can be used to monitor the components in any of these systems.

Prime Movers

The prime mover converts chemical energy in the fuel to rotational mechanical energy, which then turns an electric generator. As discussed in Chap. 2, small turbines and reciprocating engines represent the most commonly used prime movers for CHP systems, especially those with electrical outputs of less than 1 MW. Both of these prime movers release waste heat in exhaust gases and through their jackets. Jacket losses are not sufficiently large for most small turbines to warrant heat recovery, but for reciprocating engines, water at approximately 180°F or higher can be recovered by circulation of cooling water through the engine jacket. For purposes of analysis, the prime mover and electric generator will be considered as a single component. So the useful energy output is the electric power (W_{elec}), the rate of energy input is the energy content (based on lower heating value, LHV) of fuel flowing into the prime mover ($Q_{\text{Fuel,engine}}$), and the unused power released from this component is the sum of the heat losses in the exhaust gases and through the jacket.

Efficiency of Prime Movers

The *electrical generation efficiency* (η_{EE}) for the prime mover / electric generator combination is

$$\eta_{\text{EE}} = \frac{W_{\text{elec}}}{Q_{\text{Fuel,engine}}} \quad (17-2)$$

This is also the electric generation efficiency of entire CHP systems for which there is no additional electricity production (e.g., by a steam turbine) using heat recovered from the exhaust gases of the prime mover and no additional fuel input to other components for supplemental heating. The rate of energy input to the engine can be expressed as

$$\begin{aligned} Q_{\text{Fuel,engine}} &= \dot{m}_{\text{Fuel}} \text{LHV}_{\text{Fuel}} \\ &= \rho_{\text{Fuel}} \dot{v}_{\text{Fuel}} \text{LHV}_{\text{Fuel}} \end{aligned} \quad (17-3)$$

where $\dot{m}_{\text{Fuel}}$ = mass flow rate of fuel into the prime mover
 $\dot{v}_{\text{Fuel}}$ = volumetric flow rate of the fuel
 LHV_{Fuel} and ρ_{Fuel} = lower heating value and density of the fuel, respectively, evaluated at the input conditions

Combining Eqs. (17-2) and (17-3), the electric generation efficiency can be expressed in terms of measurable variables as

$$\eta_{\text{EE}} = \frac{W_{\text{elec}}}{\dot{m}_{\text{Fuel}} \text{LHV}_{\text{Fuel}}} \quad (17-4)$$

or

$$\eta_{\text{EE}} = \frac{W_{\text{elec}}}{\rho_{\text{Fuel}} \dot{v}_{\text{Fuel}} \text{LHV}_{\text{Fuel}}} \quad (17-5)$$

where Eq. (17-4) can be used when fuel consumption is measured as a mass flow rate, and Eq. (17-5) can be used when fuel consumption is measured as a volumetric flow rate.

The *prime mover efficiency* (η_{engine}) is given by the relation

$$\eta_{\text{engine}} = \frac{W_{\text{engine}}}{Q_{\text{Fuel,engine}}} \quad (17-6)$$

where W_{engine} is the rotational mechanical power output of the engine (turbine or reciprocating engine).

There are also losses from the electric generator, which ultimately dissipate as heat losses through the generator casing and can be accounted for with the *electric generator efficiency*:

$$\eta_{\text{generator}} = \frac{W_{\text{elec}}}{W_{\text{engine}}} \quad (17-7)$$

where W_{engine} represents the mechanical shaft power output of the prime mover, which equals the mechanical power input to the electric generator. When a gearbox is used between the prime mover and the electric generator, the electric generator efficiency can be expressed as

$$\eta_{\text{generator}} = \frac{W_{\text{elec}}}{W_{\text{gearbox}}} \quad (17-8)$$

where W_{gearbox} is the mechanical shaft power output from the gearbox to the generator. In this case, the gearbox efficiency (η_{gearbox}) is the ratio of the mechanical shaft output of the gearbox to the mechanical shaft output of the prime mover, that is,

$$\eta_{\text{gearbox}} = \frac{W_{\text{gearbox}}}{W_{\text{engine}}} \quad (17-9)$$

The electrical generation efficiency can be expressed as the product of these three component efficiencies, that is,

$$\eta_{\text{EE}} = \eta_{\text{engine}} \eta_{\text{gearbox}} \eta_{\text{generator}} \quad (17-10)$$

Equation (17-10) shows, together with Eqs. (17-6) through (17-9), that more detailed measurements could be used to isolate degradation of electrical generation efficiency to either the engine (prime mover), the gearbox, or the electric generator. If no gearbox is used in the system (e.g., in the case of microturbine used as the prime mover), η_{gearbox} is set to 1.0 in Eq. (17-10).

Heat Recovery Unit

As discussed in Chap. 4, heat recovery units (HRUs) are an essential part of a CHP system because they provide a means to recover heat from the exhaust gas of the prime mover (turbine or reciprocating engine). Although there are several types of HRUs used with CHP systems, only those that use indirect heating methods are considered in this chapter: (1) indirect heating to provide hot water, (2) indirect heating to provide hot dry air, and (3) indirect heating to provide process steam (described in the next section). Some CHP applications use auxiliary firing (also called co-firing or supplemental firing) to augment heat from the exhaust gases. Therefore, the HRU effectiveness equations are developed assuming that there is auxiliary firing.

Effectiveness of Heat Recovery System

The effectiveness of the HRU is defined as the ratio of the actual heat transfer rate to the maximum possible heat transfer rate, that is,

$$\epsilon_{\text{HRU}} = \frac{Q_{\text{HRU, actual}}}{Q_{\text{HRU, max}}} \quad (17-11)$$

where $Q_{\text{HRU, actual}}$ is the rate of thermal energy gain across the HRU by the heat recovery fluid (e.g., heated water, heated air or water converted to steam) and $Q_{\text{HRU, max}}$ is the maximum possible rate of heat loss by the waste heat stream from the prime mover as it passes through the HRU. If the cold-side material does not change phase in the HRU, $Q_{\text{HRU, actual}}$ can be written as

$$Q_{\text{HRU, actual}} = (\rho \dot{v} c_p)_{\text{HRU, w}} (T_{\text{HRU, w, o}} - T_{\text{HRU, w, i}}) \quad (17-12)$$

where $T_{\text{HRU, w, o}}$ is temperature of water exiting the HRU and $T_{\text{HRU, w, i}}$ is the temperature of water entering the HRU.

The maximum possible heat transfer through the HRU, $Q_{\text{HRU, max}}$ can be written (for the non-phase-change case) as

$$Q_{\text{HRU, max}} = (\rho \dot{v} c_p)_{\text{HRU, min}} (T_{\text{HRU, ex, i}} - T_{\text{HRU, w, i}}) \quad (17-13)$$

where, $(\rho \dot{v} c_p)_{\text{HRU, min}}$ is the smaller of the two quantities, $(\rho \dot{v} c_p)_{\text{HRU, ex}}$ (for the exhaust gas flow) and $(\rho \dot{v} c_p)_{\text{HRU, w}}$ (for the heat recovery stream). Although the temperature of the exhaust gas may change significantly across the HRU, Eq. (17-13) remains valid even when $(\rho \dot{v} c_p)_{\text{HRU, min}} = (\rho \dot{v} c_p)_{\text{HRU, ex}}$ because the mass flow rate of exhaust gas $(\rho \dot{v})_{\text{HRU, ex}}$ at the HRU inlet equals its value at the outlet under steady-state conditions. Furthermore, the heat capacity of the exhaust gas varies by less than 10 percent between representative HRU inlet and outlet conditions (see, for example, Kovacic 1982), further supporting the assumptions implicit in using Eq. (17-13). To reduce errors associated with using a

constant value for the heat capacity, $c_{p,\text{ex}}$ can be evaluated at the average of the HRU inlet and outlet temperatures.

Using Eqs. (17-12) and (17-13), Eq. (17-11) can be rewritten as

$$\epsilon_{\text{HRU}} = \frac{(\rho \dot{v} c_p)_{\text{HRU},w} (T_{\text{HRU},w,o} - T_{\text{HRU},w,i})}{(\rho \dot{v} c_p)_{\text{HRU},\min} (T_{\text{HRU},\text{ex},i} - T_{\text{HRU},w,i})} \quad (17-14)$$

Similarly, if hot air is generated instead of hot water, Eq. (17-14) can be rewritten as

$$\epsilon_{\text{HRU}} = \frac{(\rho \dot{v} c_p)_{\text{HRU},a} (T_{\text{HRU},a,o} - T_{\text{HRU},a,i})}{(\rho \dot{v} c_p)_{\text{HRU},\min} (T_{\text{HRU},\text{ex},i} - T_{\text{HRU},a,i})} \quad (17-15)$$

One of the flow rates appearing in Eq. (17-14) can be eliminated using a heat balance on the HRU, that is, the heat loss by the exhaust gas as it passes through the HRU ($Q_{\text{HRU},\text{ex}}$) is equal to the sum of the heat gain by the water as it passes through the HRU ($Q_{\text{HRU},w}$) and heat losses through the walls of the HRU (L_{HRU}):

$$Q_{\text{HRU},\text{ex}} = Q_{\text{HRU},w} + L_{\text{HRU}} \quad (17-16)$$

Here,

$$Q_{\text{HRU},\text{ex}} = (\rho \dot{v} c_p)_{\text{HRU},\text{ex}} (T_{\text{HRU},\text{ex},i} - T_{\text{HRU},\text{ex},o}) \quad (17-17)$$

and

$$Q_{\text{HRU},w} = (\rho \dot{v} c_p)_{\text{HRU},w} (T_{\text{HRU},w,o} - T_{\text{HRU},w,i}) \quad (17-18)$$

The rate of heat loss through the walls will generally be very small compared to both $Q_{\text{HRU},\text{ex}}$ and $Q_{\text{HRU},w}$ [approximately 1.5 percent of $Q_{\text{HRU},\text{ex}}$ for a heat recovery steam generator (HRSG) according to Kovacic (1982), p. 213]. Therefore, L_{HRU} can be neglected without introducing significant errors, and $\dot{v}_{\text{HRU},\text{ex}}$ can be obtained as a function of $\dot{v}_{\text{HRU},w}$ from Eq. (17-16) as

$$\dot{v}_{\text{HRU},\text{ex}} = \frac{(\rho c_p)_{\text{HRU},w} (T_{\text{HRU},w,o} - T_{\text{HRU},w,i})}{(\rho c_p)_{\text{HRU},\text{ex}} (T_{\text{HRU},\text{ex},i} - T_{\text{HRU},\text{ex},o})} \dot{v}_{\text{HRU},w} \quad (17-19)$$

Substituting this expression for $\dot{v}_{\text{HRU},\text{ex}}$ into Eq. (17-14), we obtain

$$\epsilon_{\text{HRU}} = \frac{(T_{\text{HRU},\text{ex},i} - T_{\text{HRU},\text{ex},o})}{(T_{\text{HRU},\text{ex},i} - T_{\text{HRU},w,i})} \quad (17-20)$$

for an HRU that uses exhaust gases from a prime mover to produce hot water, when $(\rho \dot{v} c_p)_{\text{HRU},\min} = (\rho \dot{v} c_p)_{\text{HRU},\text{ex}}$, which will ordinarily be true.

Following similar logic for an HRU that uses exhaust from a prime mover to heat air, from Eq. (17-15),

$$\epsilon_{\text{HRU}} = \frac{(T_{\text{HRU},\text{ex},i} - T_{\text{HRU},\text{ex},o})}{(T_{\text{HRU},\text{ex},i} - T_{\text{HRU},a,i})} \quad (17-21)$$

when $(\rho \dot{v} c_p)_{\text{HRU},\min} = (\rho \dot{v} c_p)_{\text{HRU},\text{ex}}$

Also from Eq. (17-15),

$$\epsilon_{\text{HRU}} = \frac{(T_{\text{HRU},a,o} - T_{\text{HRU},a,i})}{(T_{\text{HRU},\text{ex},i} - T_{\text{HRU},a,i})} \quad (17-22)$$

when $(\rho \dot{v} c_p)_{\text{HRU},\min} = (\rho \dot{v} c_p)_{\text{HRU},a}$

Determination of which fluid provides $(\rho \dot{v} c_p)_{\text{HRU},\min}$ and, therefore, whether to use Eqs. (17-21) and (17-22), for an HRU heating air, can be accomplished using the following relations obtained by rearranging Eq. (17-19) (with conditions for water replaced with conditions for air):

$$(\rho \dot{v} c_p)_{\text{HRU},\min} = (\rho \dot{v} c_p)_{\text{HRU},\text{ex}} \text{ for } (T_{\text{HRU},\text{ex},i} - T_{\text{HRU},\text{ex},o}) > (T_{\text{HRU},a,o} - T_{\text{HRU},a,i}) \quad (17-23)$$

and

$$(\rho \dot{v} c_p)_{\text{HRU},\min} = (\rho \dot{v} c_p)_{\text{HRU},a} \text{ for } (T_{\text{HRU},a,o} - T_{\text{HRU},a,i}) > (T_{\text{HRU},\text{ex},i} - T_{\text{HRU},\text{ex},o}) \quad (17-24)$$

By using Eqs. (17-20) through (17-24), the effectiveness of an HRU using exhaust gases to produce hot air or hot water can be determined from temperature measurements alone, without the need for any flow rate measurement. However, to determine the useful heat output of the HRU, one flow rate must be measured.

Heat Recovery Unit Effectiveness Calculation

To estimate the HRU effectiveness (one of the outputs shown), three temperature measurements are needed [see Eq. (17-20)]. Furthermore, to determine the rate of useful heat output ($Q_{\text{HRU},\text{actual}}$) from the HRU, the flow rate of the water and one additional temperature ($T_{\text{HRU},w,o}$) must be measured [see Eq. (17-12)]. The measurement of auxiliary input flow is optional and is not needed to estimate the effectiveness or the rate of useful heat output. In addition to the five measured inputs, the specific heat and the density of water are also needed.

For an HRU producing hot air from exhaust gases, four temperature measurements are required to determine which fluid establishes $(\rho \dot{v} c_p)_{\text{HRU},\min}$ using Eqs. (17-23) and (17-24), and then three of those measurements are used to calculate the HRU effectiveness from Eq. (17-21) or (17-22). No flow rate measurements are required to determine the HRU effectiveness; however, as with the HRU that produces hot water, determination of the rate of useful heat output requires measurement of one flow rate, preferably the flow rate of air, and values for the specific heat and density of the air (only the specific heat if the mass flow rate is measured directly). The accuracy of results can be increased by evaluating the specific heat of gases at the average of inlet and outlet conditions.

Heat Recovery Steam Generator

A heat recovery steam generator (HRSG) is a heat exchanger that recovers heat from a hot gas stream and produces steam that can be used in a thermal process or used to drive a steam turbine. A common application for a HRSG is in a combined cycle power plant, where hot exhaust from a gas turbine is fed to an HRSG to generate steam, which

in turn drives a steam turbine. In CHP applications, the HRSG is generally used to generate steam to meet facility thermal demands by firing an absorption chiller or running a steam turbine-driven chiller. An HRSG is similar to an HRU. The main difference between the HRU and HRSG is that the HRSG generates steam instead of hot water or hot air.

Effectiveness of Heat Recovery Steam Generator

The *effectiveness of a heat recovery steam generator* (ϵ_{HRSG}) also can be determined from the general equation for ϵ_{HRU} , Eq. (17-11). In this case, the actual heat transfer includes the heat of vaporization of the water as well as the sensible heat used to increase its temperature. Therefore, when expressed in terms of the change in the water side, the rate of heat transfer is equal to the difference in enthalpy between the water entering the HRSG and the steam leaving the HRSG, both of the enthalpies being functions of the fluid temperatures and pressures, that is,

$$Q_{\text{HRSG,actual}} = (\dot{v}\rho)_{\text{HRSG,w,i}} [h(T_o, P_o)_{\text{HRSG,steam,o}} - h(T_i, P_i)_{\text{HRSG,w,i}}] \quad (17-25)$$

under the assumption that the mass flow rate of water input to the HRSG is equal to the mass flow rate of steam output. Here, $h_{\text{HRSG,steam,o}}$ is the specific enthalpy of steam leaving the HRSG at temperature T_o and pressure P_o , and $h_{\text{HRSG,w,i}}$ is the specific enthalpy of the water entering the HRSG at temperature T_i and pressure P_i . The volumetric flow rate ($\dot{v}_{\text{HRSG,w,i}}$) and density ($\rho_{\text{HRSG,w,i}}$) are for water at the inlet to the HRSG.

Alternatively, the rate of heat transfer could be determined for the rate of heat loss from the hot exhaust gas as it passes through the HRSG (assuming that jacket heat losses are negligible). In this case, the rate of heat transfer is given by the relation

$$Q_{\text{HRSG,actual}} = (\dot{v}\rho c_p)_{\text{HRSG,ex,i}} (T_{\text{HRSG,ex,i}} - T_{\text{HRSG,ex,o}}) \quad (17-26)$$

where $\dot{v}_{\text{HRSG,ex,i}}$ and $\rho_{\text{HRSG,ex,i}}$ are, respectively, the volumetric flow rate and density of exhaust gas coming into the HRSG; $c_{p,\text{ex}}$ is the specific heat of the exhaust gas mixture; and $T_{\text{HRSG,ex,i}}$ and $T_{\text{HRSG,ex,o}}$ are the temperatures of the exhaust gas streams coming into and leaving the HRSG, respectively.

The maximum possible rate of heat transfer between the two fluids ($Q_{\text{HRSG,max}}$) is given by

$$Q_{\text{HRSG,max}} = (\dot{v}\rho c_p)_{\text{HRSG,ex,i}} (T_{\text{HRSG,ex,i}} - T_{\text{HRSG,w,i}}) \quad (17-27)$$

where $T_{\text{HRSG,w,i}}$ is the temperature of the saturated liquid water coming into the HRSG.

Therefore, for an HRSG, the effectiveness can be expressed as*

$$\epsilon_{\text{HRSG}} = \frac{(\dot{v}\rho)_{\text{HRSG,w,i}} [h(T_o, P_o)_{\text{HRSG,steam,o}} - h(T_i, P_i)_{\text{HRSG,w,i}}]}{(\dot{v}\rho c_p)_{\text{HRSG,ex,i}} (T_{\text{HRSG,ex,i}} - T_{\text{HRSG,w,i}})} \quad (17-28)$$

or

$$\epsilon_{\text{HRSG}} = \frac{T_{\text{HRSG,ex,i}} - T_{\text{HRSG,ex,o}}}{T_{\text{HRSG,ex,i}} - T_{\text{HRSG,w,i}}} \quad (17-29)$$

* Assuming that $(\dot{v}\rho c_p)_{\text{ex,i}} < (\dot{v}\rho c_p)_{\text{w,i}}$

HRSGs often have stages, which produce steam at different pressures (e.g., high-pressure steam, medium-pressure steam, and low-pressure steam). In these cases, the enthalpy difference of each output stream must be considered separately, so that

$$Q_{\text{HRSG,actual}} = \sum_j \left[\dot{v}_{\text{HRSG},s,o} \rho_{\text{HRSG},s,o} h(T_o, P_o)_{\text{HRSG,steam},o} \right] - \dot{v}_{\text{HRSG},w,i} \rho_{\text{HRSG},w,i} h(T_i, P_i)_{\text{HRSG},w,i} \quad (17-30)$$

and

$$\epsilon_{\text{HRSG}} = \frac{\sum_j \left[(\dot{v}\rho)_{\text{HRSG},s,o} h(T_o, P_o)_{\text{HRSG,steam},o} \right] - (\dot{v}\rho)_{\text{HRSG},w,i} h(T_i, P_i^*)_{\text{HRSG},w,i}}{(\dot{v}\rho)_p_{\text{HRSG},ex,i} (T_{\text{HRSG},ex,i} - T_{\text{HRSG},w,i})} \quad (17-31)$$

Here, the summation in the numerator is over all HRSG stages of steam production with the flow rate, density, and enthalpy for each stage corresponding to the conditions (e.g., temperature and pressure) of the steam flow exiting the j th stage of the HRSG. If energy losses from the HRSG are negligible and essentially all of the energy transferred from the exhaust gas is used to produce steam, the effectiveness of the HRSG can still be determined from the relation

$$\epsilon_{\text{HRSG}} = \frac{T_{\text{HRSG},ex,i} - T_{\text{HRSG},ex,o}}{T_{\text{HRSG},ex,i} - T_{\text{HRSG},w,i}} \quad (17-32)$$

Heat Recovery Steam Generator Calculation

To estimate the HRSG effectiveness (ϵ_{HRSG}), three temperature measurements are needed [see Eq. (17-32)]. To determine the rate of useful heat output [$Q_{\text{HRSG,actual}}$; see Eq. (17-30)] from the HRSG, additional measurements are needed. These include the flow rate of the water input to the HRSG, the flow rate, temperature, and pressure for each steam flow output from the HRSG, along with the corresponding water and steam densities. In addition, enthalpy tables are needed from which to determine the specific enthalpies of each steam flow and the water flow from their corresponding measured temperatures and pressures. The measurement of auxiliary input flow is optional and is not needed to estimate the effectiveness or the rate of useful heat output; however, its measurement will provide information useful to characterizing the fuel use and overall performance of the CHP system.

Absorption Chiller

As discussed in Chap. 4, absorption chillers are cooling machines that operate similarly to the mechanically/electrically driven (vapor-compression cycle-based) chillers, except for the compression process. Like vapor-compression cycle-based chillers, absorption chillers use a condenser, evaporator, and expansion device. The main difference between the two types of chillers is how the low-pressure vapor exiting the evaporator is converted to high-pressure vapor that enters the condenser. Instead of a mechanically driven compressor, absorption chillers use heat to drive the refrigeration cycle. The heat needed to operate an absorption chiller can be delivered directly or indirectly. In a

*Note that because water entering the HRSG is in the liquid state, $h_{w,i}$ is essentially a function of temperature only, so that $P_{\text{HRSG},i}$ need not be measured.

direct-fired absorption system, heat is provided directly by hot exhaust gases from the prime mover, while indirect-fired systems use either steam or hot water to power the refrigeration cycle. If supplemental heat is needed, it can be provided by burning auxiliary fuel in a duct heater placed in the exhaust gas stream.

Efficiency of Absorption Chiller

The *efficiency of an absorption chiller* is given by the coefficient of performance ($\text{COP}_{\text{AbChiller}}$) defined as

$$\text{COP}_{\text{AbChiller}} = \frac{Q_{\text{evap}}}{Q_{\text{gen}}} \quad (17-33)$$

where Q_{evap} is the rate at which water is cooled by the evaporator; Q_{gen} is the heat input equal to the rate of heat loss from the exhaust gas, steam or hot water as it passes through the absorption unit's generator to desorb the refrigerant from the weak solution; and W_{in} is the pump energy, which is small compared to Q_{evap} and is ignored.

Here,

$$\begin{aligned} Q_{\text{evap}} &= \dot{m}_{\text{evap},w,i} c_{p,w} (T_{\text{evap},w,i} - T_{\text{evap},w,o}) \\ &= \dot{v}_{\text{evap},w,i} \rho_{\text{evap},w,i} c_{p,w} (T_{\text{evap},w,i} - T_{\text{evap},w,o}) \end{aligned} \quad (17-34)$$

where $\dot{m}_{\text{evap},w,i}$ = mass flow rate of chilled water into the evaporator
 $\dot{v}_{\text{evap},w,i}$ = volumetric flow rate of chilled water entering the evaporator
 $\rho_{\text{evap},w,i}$ and $c_{p,w}$ = density and specific heat of chilled water entering the evaporator, respectively
 $T_{\text{evap},w,i}$ and $T_{\text{evap},w,o}$ = evaporator entering and leaving chilled water temperatures

For direct-fired absorption chillers:

$$Q_{\text{gen}} = \dot{v}_{\text{ex},i} \rho_{\text{ex},i} c_{p,\text{ex}} (T_{\text{ex},i} - T_{\text{ex},o}) \quad (17-35)$$

where $\rho_{\text{ex},i}$ = density of the exhaust gases entering the absorption chiller
 $\dot{v}_{\text{ex},i}$ = volumetric flow rate of exhaust gases entering the chiller
 $c_{p,\text{ex}}$ = specific heat of the exhaust gases (evaluated at the average exhaust gas temperature in the chiller)*
 $T_{\text{ex},i}$ and $T_{\text{ex},o}$ = exhaust gas entering and leaving temperatures, respectively

For absorption chillers that use hot water from an HRU to generate the refrigerant:

$$Q_{\text{gen}} = \dot{v}_{\text{hotwater},i} \rho_{\text{hotwater},i} c_{p,\text{hotwater}} (T_{\text{hotwater},i} - T_{\text{hotwater},o}) \quad (17-36)$$

*The product of volumetric flow rate of the exhaust gas and its density, which is the mass flow rate, is constant through the chiller during steady operation; therefore, $\dot{v}_{\text{ex},i} \rho_{\text{ex},i} = \dot{v}_{\text{ex},o} \rho_{\text{ex},o}$, and this quantity can be evaluated at either the inlet or exit conditions. We recommend evaluating $c_{p,\text{ex}}$ at the average of the inlet and outlet temperatures of the exhaust gas; however, the difference in the value of $c_{p,\text{ex}}$ evaluated at the inlet conditions and the outlet conditions will be less than about 8 percent for the exhaust gases in most practical situations.

where $\rho_{\text{hotwater},i}$ and $c_{p,\text{hotwater}}$ = density and specific heat of hot water entering the absorption chiller

$\dot{v}_{\text{hotwater},i}$ = volumetric flow rate of hot water entering the chiller
 $T_{\text{hotwater},i}$ and $T_{\text{hotwater},o}$ = hot water entering and leaving temperatures

For absorption chillers that use steam to generate the refrigerant:

$$Q_{\text{gen}} = \dot{v}_{\text{steam},i} \rho_{\text{steam},i} [h(T_i, P_i)_{\text{steam},i} - h(T_o, P_o)_{\text{steam},o}] \quad (17-37)$$

where $\rho_{\text{steam},i}$ = density of steam entering the absorption chiller

$\dot{v}_{\text{steam},i}$ = volumetric flow rate of steam entering the chiller

$h(T_i, P_i)$ = enthalpy of steam entering the chiller at temperature T_i and pressure P_i

$h(T_o, P_o)$ = enthalpy of steam leaving the chiller at temperature T_o and pressure P_o

Absorption Chiller Performance Calculations

For absorption chillers with hot water or steam as the source of heat, the performance calculations are based on Eqs. (17-33), (17-34), and (17-36) or (17-37). For direct-fired absorption chillers, the performance algorithms are based on Eqs. (17-33) through (17-35). The density of liquid water or exhaust gases should be evaluated at the same conditions as the inlet flow rate is measured. The specific heats of water and exhaust gases are assumed constant across the chiller, which is a good assumption for liquid water for the typical range of temperatures across the chiller, but it should be evaluated at the average of the inlet and outlet temperatures for exhaust gas. Although, the auxiliary fuel flow rate is not included in the equations cited for direct-fired absorption chillers, the auxiliary fuel flow rate is input into the algorithms and converted to an output as the auxiliary rate of fuel use so that fuel used for supplemental firing can be tracked (it is not included as an output for hot-water- and steam-fired chillers because it is an output for the HRU in those cases).

Cooling Tower

Cooling towers (CTs) provide an ability to reject heat from the condenser and the absorber, which is required by the absorption refrigeration cycle. For a water-cooled condenser, heat is transferred from refrigerant to cool water, which is pumped to the cooling tower. The cooling tower uses evaporative cooling to reject heat from the condenser cooling water to the ambient environment. The fans push (forced draft) or pull (induced draft) ambient air through the cooling tower.

Efficiency of Cooling Towers

The *cooling tower efficiency* (η_{CT}) is defined as

$$\eta_{\text{CT}} = \frac{(T_{\text{CT},w,i} - T_{\text{CT},w,o})}{(T_{\text{CT},w,i} - T_{\text{wb}})} \quad (17-38)$$

where $T_{\text{CT},w,i}$ = inlet temperature of the cooling water return to the tower

$T_{\text{CT},w,o}$ = outlet temperature of cooled water from the tower (cooling water supply)

T_{wb} = wet-bulb temperature of the ambient air to which heat is rejected by the cooling tower*

*If heat losses from piping between the absorption chiller and cooling tower are small, then $T_{\text{CT},w,i} \approx T_{\text{AbChiller},cw,o}$ and $T_{\text{CT},w,o} \approx T_{\text{AbChiller},cw,i}$

The value of η_{CT} only indicates how well the cooling tower cools the condenser water in terms of how close the water temperature approaches the limiting wet-bulb temperature of the ambient air. It does not indicate how the cooling was achieved or how much external electrical energy input was used to achieve this reduction in temperature. For example, if the cooling tower medium becomes fouled, increasing resistance to air flow and inhibiting heat transfer, the cooling tower fans might run longer or at a higher speed (for variable speed fans) to achieve the same temperature drop for the water that was accomplished with less fan energy when the medium was not fouled. In addition, electric power is used to pump the condenser water to and from the cooling tower. To provide a metric for how efficiently electricity is used in this process, we define a *cooling tower electric utilization efficiency* ($\eta_{CT,elec}$)* as

$$\eta_{CT,elec} = \frac{Q_{CT,th}}{W_{CT,elec}} \quad (17-39)$$

where $Q_{CT,th}$ is the rate of heat rejection from the cooling tower and is equal to the heat loss by the condenser water in passing through the cooling tower and $W_{CT,elec}$ is the electric power use by the cooling tower fans and pumps. The electric power use is the sum of the electric power used by all the individual pumps and fans, that is,

$$W_{CT,elec} = \sum_j W_{CT,elec,j} \quad (17-40)$$

where $W_{CT,elec,j}$ is the electric power use by the j th pump or fan, and the summation is over all pumps and fans.

The rate of heat loss from the condenser water can be determined from measurements of the entering water temperature ($T_{CT,w,i}$), the exiting water temperature ($T_{CT,w,o}$), and the volumetric flow rate of water through the cooling tower ($\dot{v}_{CT,w}$) using the relation

$$Q_{CT,th} = \rho_w \dot{v}_{CT,w} c_{p,w} (T_{CT,w,i} - T_{CT,w,o}) \quad (17-41)$$

where ρ_w and $c_{p,w}$ are the density and specific heat of liquid water, respectively.

Combining Eqs. (17-39) through (17-41), the cooling tower electric utilization efficiency can be expressed as

$$\eta_{CT,elec} = \frac{\rho_w \dot{v}_{CT,w} c_{p,w} (T_{CT,w,i} - T_{CT,w,o})}{\sum_j W_{CT,elec,j}} \quad (17-42)$$

Cooling Tower Performance Calculation

The algorithms used to calculate the performance of the cooling tower are based on Eqs. (17-38) and (17-42). The density and specific heat of liquid water are assumed to be constant across the cooling tower. They can be evaluated at the average of the water inlet and outlet temperatures to improve accuracy.

*Including condenser water system pumps—it may be considered as condenser water system efficiency.

Pumps

Pumps use rotational mechanical energy, usually provided by an electric motor, to create the pressure differences that drive the flow of fluids.

Efficiency of Pumps

The *efficiency of a pump* (η_{pump}) can be expressed as

$$\eta_{\text{pump}} = \frac{W_{\text{pump}}}{W_{\text{pump,elec}}} \quad (17-43)$$

where W_{pump} is the mechanical power output imparted by the pump to the liquid, and $W_{\text{pump,elec}}$ is the electric power input to the pump motor. The mechanical power imparted by the pump to the liquid is equal to the product of the volumetric flow rate through the pump and the pressure difference across the pump, that is,

$$W_{\text{pump}} = \dot{v}_{\text{pump},w}(P_{\text{discharge}} - P_{\text{suction}}) \quad (17-44)$$

where $\dot{v}_{\text{pump}}$ is the volumetric flow rate through the pump, P represents pressure, and the subscripts “discharge” and “suction” identify variables at the pump suction port (inlet) and discharge port (outlet). The difference between the discharge and suction pressures on an operating pump is sometimes called the dynamic head.

Combining Eqs. (17-43) and (17-44), yields the relation for pump efficiency, which incorporates motor efficiency.

$$\eta_{\text{pump}} = \frac{\dot{v}_{\text{pump}}(P_{\text{discharge}} - P_{\text{suction}})}{W_{\text{pump,elec}}} \quad (17-45)$$

Fans

Similar to pumps, fans use rotational mechanical energy, usually provided by an electric motor, to create the pressure differences that drive the flow of gases, often air.

Efficiency of Fans

The *efficiency of a fan* (η_{fan}) can be expressed as

$$\eta_{\text{fan}} = \frac{W_{\text{fan}}}{W_{\text{fan,elec}}} \quad (17-46)$$

where W_{fan} is the mechanical power output imparted by the fan to the gas, and $W_{\text{fan,elec}}$ is the electric power input to the fan motor. The mechanical power imparted by the fan to the gas is equal to the product of the volumetric flow rate* through the fan and the pressure difference across the fan, that is,

$$W_{\text{fan}} = \dot{v}_{\text{fan}}(P_{\text{fan},o} - P_{\text{fan},i}) \quad (17-47)$$

where $\dot{v}_{\text{fan}}$ is the volumetric flow rate through the fan, and $P_{\text{fan},i}$ and $P_{\text{fan},o}$ represent the pressure immediately upstream and downstream of the fan.

*The work of compressing the air is assumed negligible, which is reasonable for fans operating at or below about 4 in w.c. (= 0.145 psig = 996 Pa).

Combining Eqs. (17-43) and (17-44), yields the relation for fan efficiency

$$\eta_{\text{Fan}} = \frac{\dot{v}_{\text{Fan}} (P_{\text{Fan},o} - P_{\text{Fan},i})}{W_{\text{Fan},\text{elec}}} \quad (17-48)$$

Equation (17-48) provides the efficiency of the fan-motor combination rather than the fan alone.

Desiccant System

A solid desiccant system can also be used in a CHP system for dehumidification because it is capable of using a low-grade thermal source to remove moisture from the air, which eliminates the overcooling and reheating steps typically employed in a conventional cooling system for dehumidification, and thus can save electrical energy and associated costs by using captured waste heat for the same process. The dry air produced by the desiccant system can be used for industrial processes or space conditioning. A solid desiccant system consists of a desiccant wheel, a supply (process) fan, an exhaust fan, and a heat source for regenerating the desiccant. In a CHP system, exhaust gases, either directly from the prime mover or indirectly after passing through an HRU, are used for reactivation of the desiccant. In some cases, additional heating is provided by a duct-burner, which supplements the heat in the exhaust stream.

Efficiency of Desiccant System

The *efficiency of the desiccant system* (η_D) is defined as the ratio of dehumidification load (rate of moisture removal) to the total electric and thermal power input for regenerating the desiccant:

$$\eta_D = \frac{Q_d}{Q_{d,\text{in}} + W_{d,\text{elec}}} \quad (17-49)$$

where Q_d = rate of dehumidification

$Q_{d,\text{in}}$ = rate at which heat is used to regenerate the desiccant

$W_{d,\text{elec}}$ = total fan power input (for both the process and the regeneration streams)

Q_d can be calculated using the following equation:

$$Q_d = Q_{d,\text{total}} - Q_{d,\text{sensible}} \quad (17-50)$$

where $Q_{d,\text{total}}$ is the rate of total heat transfer between the inlet and outlet on the supply (air) side, given by

$$Q_{d,\text{total}} = (\dot{v}\rho)_{d,a} h(T, DP)_{d,a,i} - h(T, DP)_{d,a,o} \quad (17-51)$$

$h(T, DP)_{d,a,i}$ and $h(T, DP)_{d,a,o}$ are the specific enthalpies of the entering and leaving air (process) streams at the corresponding dry-bulb and dew-point temperatures (T and DP , respectively). The mass flow measured either at the inlet or outlet of the process stream is represented by the term $(\dot{v}\rho)_{d,a}$.

$Q_{d,\text{sensible}}$ is the rate of sensible heat transfer to the process air stream between the inlet and outlet of the desiccant system and can be calculated from:

$$Q_{d,\text{sensible}} = (\dot{v}\rho c_p)_{d,a} (T_{d,a,i} - T_{d,a,o}) \quad (17-52)$$

where $T_{d,a,i}$ and $T_{d,a,o}$ are dry-bulb temperatures at the inlet and outlet of the air side of the desiccant system, respectively. The term $Q_{d,in}$ represents the regeneration energy input:

$$Q_{d,in} = (\dot{v} \rho c_p)_{d,ex} (T_{d,ex,i} - T_{d,ex,o}) \quad (17-53)$$

where $T_{d,ex,i}$ and $T_{d,ex,o}$ are dry-bulb temperatures at the inlet and outlet of the regeneration stream, respectively.

Desiccant System Performance Monitoring Calculations

The performance monitoring algorithms, with the exception of the auxiliary fuel input, are all based on Eqs. (17-49) through (17-53). The density of supply air and exhaust gases should be evaluated at the same conditions as the inlet flow rate is measured. The specific heats of the supply air and the exhaust gases are assumed constant across the desiccant system, which is a good assumption for both air and exhaust gas because the variations across the inlet and outlet are small.

Equations for the efficiency of CHP components are summarized in Table 17-1.

System-Level Performance Monitoring

System-level monitoring is needed to ensure that the overall CHP system is performing up to specifications and that significant degradation in performance has not occurred. If degradation is detected and quantified, monitored component-level information can be used to isolate the cause of degradation and correct it. This process is illustrated in the "Application Scenarios" section later in this chapter.

The system shown in Chap. 1 represents the most complete building-scale CHP system. Many of the other CHP configurations used in practice can be derived by specifying the prime mover and eliminating components.

To monitor the system-level performance of CHP systems, two metrics for efficiency and several other metrics calculated from sensed conditions or measured directly are used. The two efficiency metrics are the *overall fuel utilization efficiency* (η_F) [as defined in Eq. (17-1)] and the *value-weighted energy utilization factor* (EUF_{vw}),* which is defined as

$$EUF_{vw} = \frac{W_{elec} Y_{elec} + \sum_j Q_{th,j} Y_{th,j}}{\sum_j Q_{Fuel,j} Price_{Fuel,j}} \quad (17-54)$$

Here, W_{elec} is the net electrical power output, $Q_{th,j}$ represents the net rate of useful thermal energy output from thermal recovery and/or conversion process j (e.g., the cooling provided by an absorption chiller) with the sum being over all thermal recovery and conversion processes in the system delivering energy for end use (e.g., an absorption chiller or a desiccant unit), and Q_{Fuel} is the total rate of input of fuel energy to the CHP system. For systems with fuel used for supplemental heating (e.g., for a heat recovery unit, steam generator, or desiccant regenerator), Q_{Fuel} is the sum over all fuel inputs to the system, that is,

$$Q_{Fuel} = \sum_j Q_{Fuel,j} \quad (17-55)$$

*The EUF_{vw} was introduced by Timmermans (1978) and later elaborated upon by Horlock (1997).

Component	Purpose	Efficiency/ Effectiveness Relation	Variables
Small turbine generators	Prime mover to generate electricity	$\eta_{EE} = \frac{W_{elec}}{Q_{Fuel,engine}}$	η_{EE} = electric generation efficiency W_{elec} = net electrical power output $Q_{Fuel,engine}$ = total rate of input of fuel energy to the prime mover
Reciprocating engines	Prime mover to generate electricity	$\eta_{EE} = \frac{W_{elec}}{Q_{Fuel,engine}}$	η_{EE} = electric generation efficiency W_{elec} = net electrical power output $Q_{Fuel,engine}$ = total rate of input of fuel energy to the prime mover
Heat recovery units (HRU)	Heat exchange from hot exhaust gases from the prime mover to the heat recovery fluid	$\epsilon_{HRU} = \frac{Q_{HRU,actual}}{Q_{HRU,max}}$	ϵ_{HRU} = heat recover unit effectiveness $Q_{HRU,actual}$ = rate of heat gain by the heat recovery fluid $Q_{HRU,max}$ = maximum possible rate of heat loss from the waste heat stream from the prime mover in the HRU
Absorption chillers	Generate chilled water using heat to drive refrigerant from solution in an absorption refrigeration cycle	$COP_{AbChiller} = \frac{Q_{evap}}{Q_{gen}}$	$COP_{AbChiller}$ = coefficient of performance of the absorption chiller Q_{evap} = rate of heat loss from cooling water passing through the evaporator Q_{gen} = rate of heat loss from the heat source fluid as it passes through the refrigerant generator
Vapor-compression chillers	Generate chilled water using electric power to drive compressors in a vapor-compression refrigeration cycle	$COP_{Chiller} = \frac{Q_{evap}}{W_{ChillerElec}}$	$COP_{Chiller}$ = coefficient of performance of the chiller Q_{evap} = rate of heat loss from chilled water passing through the evaporator $W_{ChillerElec}$ = electric power input to the chiller

TABLE 17-1 Summary of Expressions for CHP Component Efficiencies

Component	Purpose	Efficiency/ Effectiveness Relation	Variables
Cooling towers	Cool chiller condenser water via evaporation and sensible heat transfer to ambient air	$\eta_{CT} = \frac{(T_{CT,w,i} - T_{CT,w,o})}{(T_{CT,w,i} - T_{wb})}$ $\eta_{CT,elec} = \frac{Q_{CT,th}}{W_{CT,elec}}$	η_{CT} = cooling tower efficiency (effectiveness) $\eta_{CT,elec}$ = cooling tower electric utilization efficiency $T_{CT,w,i}$ = inlet temperature of condenser water to the tower $T_{CT,w,o}$ = outlet temperature of condenser water from the tower T_{wb} = wet-bulb temperature of the ambient air $Q_{CT,th}$ = rate of heat loss by the cooling water as it passes through the cooling tower $W_{CT,elec}$ = electric power use by the cooling tower fans and pumps
Desiccant systems	Remove moisture from air with the desiccant regenerated using waste heat	$\eta_D = \frac{Q_d}{Q_{d,input}}$	η_D = desiccant system efficiency Q_d = rate of moisture removal from the air stream (dehumidification load) $Q_{d,input}$ = rate of heat input for desiccant generation
Pumps	Create a pressure difference in liquid to instigate flow using an electric motor as a source of mechanical rotational energy	$\eta_{Pump} = \frac{W_{Pump}}{W_{Pump,elec}}$	η_{Pump} = pump efficiency W_{Pump} = mechanical power output from the pump to the liquid $W_{Pump,elec}$ = electric power input to the pump motor
Fans	Create a pressure difference in air to support flow, using an electric motor as the source of mechanical rotational energy	$\eta_{Fan} = \frac{W_{Fan}}{W_{Fan,elec}}$	η_{Fan} = overall efficiency of the fan W_{Fan} = useful power output from the fan $W_{Fan,elec}$ = electric power input to the fan motor

TABLE 17-1 Summary of Expressions for CHP Component Efficiencies (*Continued*)

where $Q_{Fuel,j}$ is the rate of fuel energy input at point j in the system (e.g., to the prime mover or for supplemental heating of exhaust gases before entering the heat recovery unit) with the sum being over all fuel inputs to the CHP system. These fuel inputs may include the same fuel (e.g., natural gas) introduced at several different points in the system or may be different fuels (e.g., diesel fuel for a reciprocating engine prime mover

and natural gas for supplemental heat elsewhere in the system). The fuel energy may be based on the lower heating value (LHV) or higher heating value (HHV) of the fuel. By convention, the gas turbine industry uses the lower heating value to characterize energy use and calculate efficiencies, while the natural gas distribution and electric power generation industries use the HHV for sales and to characterize natural gas energy use (Energy Nexus Group 2002). Use of the LHV for determining energy use or the efficiency of small turbines and reciprocating engines in CHP systems seems reasonable because the products of combustion (exhaust) leave the turbine or engine at conditions at which the water is in vapor phase. For monitoring CHP system performance and detecting degradation over time, either the LHV or the HHV can be used as long as the use is consistent. For comparisons to benchmarks such as data from manufacturers, care must be taken to ensure that the LHV or HHV is used consistently in determination of the benchmark and in calculations of monitored performance. Furthermore, if condensing HRUs are used in the system, the HHV should be used in calculations of fuel energy inputs.

Other variables appearing in Eq. (17-54) are defined as follows: Y_{elec} and $Y_{\text{th},j}$ represent, respectively, the value per unit of electricity generated (e.g., in \$/kWh) and the value per unit of useful heat (or cooling) provided (e.g., in \$/million Btu) by the j th thermal application technology (e.g., absorption chiller or desiccant unit), and $\text{Price}_{\text{Fuel},j}$ is the price of the fuel injected at point j in the system, with the discussion of different fuels versus a single fuel from the immediately preceding paragraph applying. By accounting for the value of products, this metric represents the value of products per unit of expenditure on fuel and has units of dollar value of produced energy per dollar value of fuel consumed. In operating a plant, EUF_{vw} should be maximized to achieve the most economic operation. Because generally $Y_{\text{elec}} > Y_{\text{th},j}$ for most thermal applications, a CHP plant should be operated to maximize electricity production. If, however, the amount of electricity above on-site requirements cannot be sold to the grid, the electricity production should follow variations in on-site electric load. Changes in the value of EUF_{vw} caused by degradations in CHP system performance would be weighted by their effects on the value of the energy produced. As a result, faults and performance degradations having the greatest dollar impacts would be recognized by larger changes in the EUF_{vw} .

Other system-level variables that can be separately monitored to provide information useful for diagnosing changes in CHP system efficiency and understanding operating costs are

- Current rate of useful heating or cooling output, Q_{th} (kW_{th} or Btu/h)
- Current electric power output, W_{elec} (kW)
- Current total rate of fuel use, $Q_{\text{Fuel}} = \sum_j Q_{\text{Fuel},j}$ (kW_{Fuel}, MJ_{Fuel}/h, or Btu_{Fuel}/h)
- Current rate of expenditures on fuel, $\text{Cost}_{\text{Fuel}} = \sum_j Q_{\text{Fuel},j} \text{Price}_{\text{Fuel},j}$ (\$/h)

Average values of these metrics over various time intervals can also be constructed for each of them, for example, average daily useful heat output, daily average hourly heat output, total daily heat output, and so forth for the other variables.

These indicators of overall system performance are supplemented with the component performance indicators to enable system-level and finer resolution performance monitoring and potentially fault detection and diagnostics in support of condition-based maintenance of CHP plants.

CHP System-Level Performance Monitoring Calculations

The monitoring algorithms are based on Eqs. (17-1), (17-54), and the expressions for other monitored variables given earlier. The density, specific heat, and heating value of each fuel stream (j) must be specified. Although the density and heating value of the fuels are assumed to vary slowly compared to the time between samples of the measured inputs and, therefore, are considered fixed inputs, they could be varied by changing their values periodically based on measurement of them or information from the fuel supplier. All individual useful thermal outputs (j) must be specified to ensure proper crediting of outputs and their values ($Y_{th,j}$). System-level monitoring provides top-level indicators of the performance of the CHP plant and is supplemented by component monitoring, which provides greater detail and resolution.

Summary of Equations for Metrics

In this section we present the summary of equations for system-level metrics. Equations for these metrics are summarized in Table 17-2. The rates can be integrated to obtain average values over selected time periods, and average efficiencies and utilization factors can be determined by integrating the numerator and denominator in the corresponding expression separately and then taking their ratio. Some generic example expressions for time-integrated quantities follow.

Rates

Average value for time period t_0 to t_1

$$\begin{aligned} \text{Average quantity over last } n \text{ hours} &= \int_{t_0}^{t_1} (\text{current-rate}) dt / (t_1 - t_0) \\ &\approx \sum_{j=n_0}^{n_1} \text{current-hourly-rate}_j / (n_1 - n_0) \end{aligned} \quad (17-56)$$

where t_0 and t_1 represent the start and end times for the time interval of interest for time measured from any arbitrary origin $t = 0$; n_0 and n_1 are the corresponding time interval indices corresponding to times t_0 and t_1 ; $n_1 - n_0 = (t_1 - t_0) / \Delta t$, and Δt is the length of the time interval (e.g., 1 hour). Some specific example expressions based on Eq. (17-56) follow.

Daily Average Value

$$\begin{aligned} \text{Average value} &= \int_0^{24 \text{ hours}} (\text{current-rate}) dt \\ &\approx \sum_{j=1}^{24} \text{current-hourly-rate}_j / 24 \end{aligned} \quad (17-57)$$

Average Value for the Last n Hours

$$\begin{aligned} \text{Average quantity over last } n \text{ hours} &= \int_{t-n}^t (\text{current-rate}) dt / n \\ &\approx \sum_{j=t-n}^t \text{current-hourly-rate}_j / n \end{aligned} \quad (17-58)$$

Metric	Purpose	Functional Relation	Variables
Fuel utilization efficiency (η_F)	Indicate the overall CHP system efficiency in using fuel	$\eta_F = \frac{(W_{\text{elec}} + Q_{\text{th}})}{Q_{\text{Fuel}}}$ $= \frac{\left(\sum_j W_{\text{elec},j} + \sum_k Q_{\text{th},k} \right)}{\sum_l Q_{\text{Fuel},l}}$	η_F = fuel utilization efficiency W_{elec} = net electrical power output* Q_{th} = total useful thermal energy output of the CHP system Q_{Fuel} = total rate of fuel use by the CHP system <i>(see below for other definitions)</i>
Value-weighted energy utilization factor (EUF_{vw})	Indicate the overall CHP system efficiency based on monetary value of input fuel and output energy	$\text{EUF}_{\text{vw}} = \frac{\text{net value of system outputs}}{\text{Cost}_{\text{Fuel}}}$ $= \frac{\sum_j W_{\text{elec},j} Y_{\text{elec},j} + \sum_k Q_{\text{th},k} Y_{\text{th},k}}{\sum_l Q_{\text{Fuel},l} \text{Price}_{\text{Fuel},l}}$	EUF_{vw} = value-weighted energy utilization factor Y_{elec} = unit value of electricity produced $Y_{\text{th},j}$ = unit value of useful thermal energy output stream j $\text{Price}_{\text{Fuel},j}$ = price of fuel for fuel input j to the CHP system $\text{Cost}_{\text{Fuel}}$ = total rate of expenditure on fuel for the system <i>(see below for other definitions)</i>
Current rate of useful thermal output (Q_{th})	Indicate the rate of useful thermal output for heating or cooling by the CHP system	$Q_{\text{th}} = \sum_j Q_{\text{th},j}$	Q_{th} = total useful thermal energy output of the CHP system $Q_{\text{th},j}$ = useful thermal energy output j of the CHP system
Current electric power output (W_{elec})	Indicate the net electric power output from the CHP system	$W_{\text{elec}} = \sum_j W_{\text{elec},j}$	W_{elec} = net electrical power output of the CHP system $W_{\text{elec},j}$ = electrical output j from the CHP system (parasitic uses of electricity take negative values)
Current total rate of fuel use (Q_{Fuel})	Indicate the total rate of fuel use by the CHP system	$Q_{\text{Fuel}} = \sum_j Q_{\text{Fuel},j}$	Q_{Fuel} = total rate of fuel use by the CHP system $Q_{\text{Fuel},j}$ = rate of fuel use by fuel input j to the CHP system

*The electricity terms include negative values corresponding to parasitic electricity use by pumps, fans, etc.

TABLE 17-2 Summary of Functional Relations for CHP System-Level Metrics

Metric	Purpose	Functional Relation	Variables
Current expenditure rate for fuel (Cost _{Fuel})	Indicate the rate of expenditure of funds on fuel for the CHP plant	$Cost_{Fuel} = \sum_j Q_{Fuel,j} Price_{Fuel,j}$	Cost _{Fuel} = total rate of monetary expenditure on fuel for the system Q _{Fuel,j} = rate of fuel use by fuel input <i>j</i> to the CHP system Price _{Fuel,j} = price of fuel for fuel input <i>j</i> to the CHP system

TABLE 17-2 Summary of Functional Relations for CHP System-Level Metrics (Continued)

For example, the daily average value for electricity production by the CHP system based on Eq. (17-57) is given as

Daily average electric power output = $\int_0^{24\text{hours}} W_{elec} dt$

(17-59)

Efficiencies and Utilization Factors

Average value for time period *t*₀ to *t*₁

Daily average value = $\frac{\int_{t_0}^{t_1} (\text{metricnum}) dt}{\int_{t_0}^{t_1} (\text{metricdenom}) dt}$

(17-60)

$\approx \frac{\sum_{j=n_0}^{n_1} \text{metricnum}_j}{\sum_{j=n_0}^{n_1} \text{metricdenom}_j}$

Example applications of Eq. (17-60) to daily average efficiency or effectiveness and average over the last *n* hours follow.

Daily Average Value

Daily average value = $\frac{\int_0^{24\text{hours}} (\text{metricnum}) dt}{\int_0^{24\text{hours}} (\text{metricdenom}) dt}$

(17-61)

$\approx \frac{\sum_{j=1}^{24} \text{metricnum}_j}{\sum_{j=1}^{24} \text{metricdenom}_j}$

where metricnum and metricdenom are the numerator and denominator of the efficiency, effectiveness or utilization factor. For example, applying Eq. (17-61) to the fuel utilization efficiency,

$$\begin{aligned} \text{Average daily } \eta_F &= \frac{\int_0^{24\text{hours}} (W_{\text{elec}} + \sum_j Q_{\text{th},j}) dt}{\int_0^{24} Q_{\text{Fuel}} dt} \\ &\approx \frac{\sum_{j=1}^{24} \left(W_{\text{elec}} + \sum_k Q_{\text{th},k} \right)_j}{\sum_{j=1}^{24} Q_{\text{Fuel},j}} \end{aligned} \quad (17-62)$$

where the sum over the index j is for the 24 hours of the day and the sum over index k is over all useful thermal outputs of the CHP system.

Average Value for the Last n Hours

$$\begin{aligned} \text{Average metric value over last } n \text{ hours} &= \frac{\int_{t-n}^t (\text{metricnum}) dt}{\int_{t-n}^t (\text{metricdenom}) dt} \\ &\approx \frac{\sum_{j=t-n}^t \text{metricnum}_j}{\sum_{j=t-n}^t \text{metricdenom}_j} \end{aligned} \quad (17-63)$$

As an example, applying Eq. (17-63) to the value-weighted energy utilization factor (EUF_{vw}),

$$\begin{aligned} \text{Average } \text{EUF}_{\text{vw}} \text{ over last 8 hours} &= \frac{\int_{t-8}^t (W_{\text{elec}} Y_{\text{elec}} + \sum_k Q_{\text{th},k} Y_{\text{th},k}) dt}{\int_{t-8}^t \left(\sum_l Q_{\text{Fuel},l} \text{Price}_{\text{Fuel},l} \right) dt} \\ &\approx \frac{\sum_{j=-8}^0 \left(W_{\text{elec}} Y_{\text{elec}} + \sum_k Q_{\text{th},k} Y_{\text{th},k} \right)_j}{\sum_{j=-8}^0 \left(\sum_l Q_{\text{Fuel},l} \text{Price}_{\text{Fuel},l} \right)_j} \end{aligned} \quad (17-64)$$

Here, the summation over j is for each of the last 8 hours, the summation over k is for all useful thermal energy outputs from the system, and the summation over l is for all

fuel streams into the CHP system. All variables in Eqs. (17-56) through (17-64) are defined in Table 17-2.

Equations (17-56) through (17-64) can be used to determine average values of any of the system-level metrics identified earlier in this section and in Table 17-2. Averages for longer time periods (e.g., a week or a month) can be obtained by increasing the limits on the integrations or summations to the corresponding start and end times for which the average values are desired.

Example Application of Data from Simulation and Laboratory Testing

This section demonstrates the use of the algorithms developed in this project for monitoring the performance of a CHP system and detecting faults and performance degradation. The demonstration uses both simulated data from models and data from the laboratory to demonstrate the use of the algorithms developed in the previous section.

The data used for testing were recorded from the CHP system in the Integrated Energy Systems (IES) Laboratory at Oak Ridge National Laboratory, ORNL (Rizy et al. 2002 and 2003; Zaltash et al. 2006). The CHP system consists of a microturbine generator (MTG), exhaust-to-water heat recovery unit (HRU), hot water-fired absorption chiller, and cooling tower. The MTG is a 30-kW natural gas-fired Capstone unit that produces three-phase 480-V AC electric power and releases exhaust gases in the approximate temperature range 480 to 560°F. A gas compressor is used to raise the pressure of the natural gas provided by the distributor (at 5 psig) to the pressure of 55 psig required by the MTG. The unit uses heat recuperation to preheat the air before it enters the combustion chamber, which increases electrical generation efficiency and reduces the available exhaust heat. The hot exhaust gases pass through a gas-to-water heat recovery unit, producing hot water at 185 to 203°F. The exhaust gases are then vented to the atmosphere at approximately 248°F. To increase fuel utilization efficiency, these vented gases could be used to feed a direct-fired desiccant unit, which is possible at the IES lab, but the IES system is configured with exhaust gases venting from the HRU directly to the atmosphere for these tests. The hot water output from the HRU is used to thermally power a 10-ton (35-kW) single-effect LiBr-water absorption chiller, providing chilled water at approximately 44°F. Cooling for the chiller condenser is provided by a closed cooling-water loop that uses a wet cooling tower to reject heat to the environment.

A schematic of the CHP monitoring system is shown in Fig. 17-1. The monitoring system not only shows the measured data from the sensors, it also shows the calculated performance data. The data collected at ORNL were fed into the monitoring system to simulate real-time CHP operation. The calculated values are shown in the left bottom portion of the monitoring screen (Fig. 17-1) or inside the component. The monitoring system is also capable of setting alarm limits for the sensor values and the calculated values. Although the monitoring system shows measured or calculated values for any given time and alarm, if a value is out of a reasonable range, it does not show up on the trends.

The efficiencies are calculated using equations summarized in Tables 17-1 and 17-2. Trends for the efficiency, effectiveness and energy utilization factor are shown in Figs. 17-2 and 17-3.

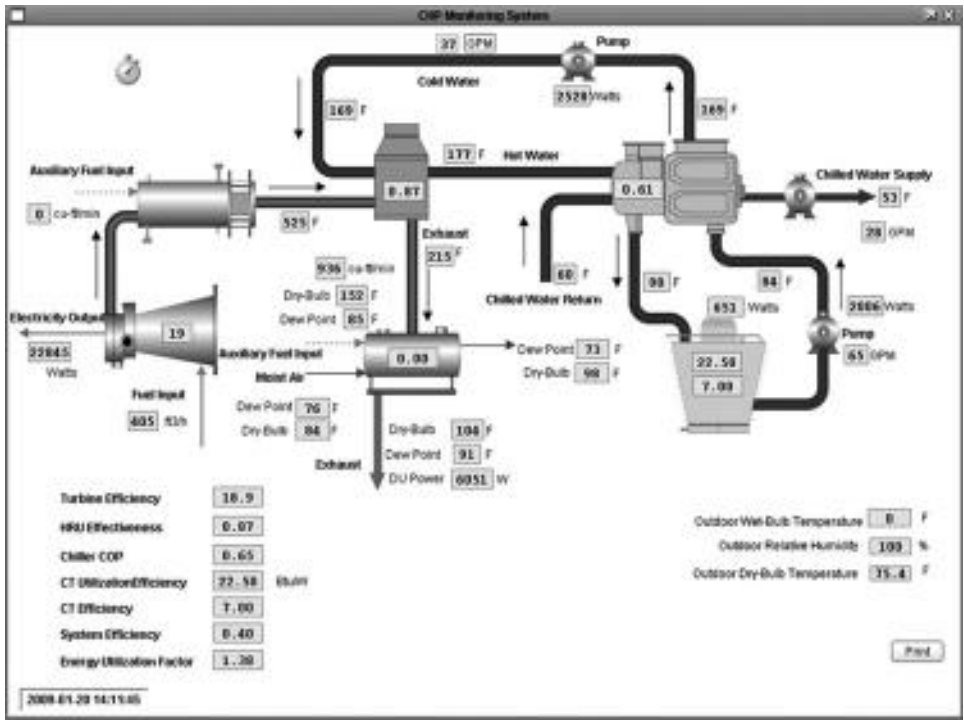


FIGURE 17-1 Schematic diagram of CHP monitoring system used to test performance monitoring algorithms.

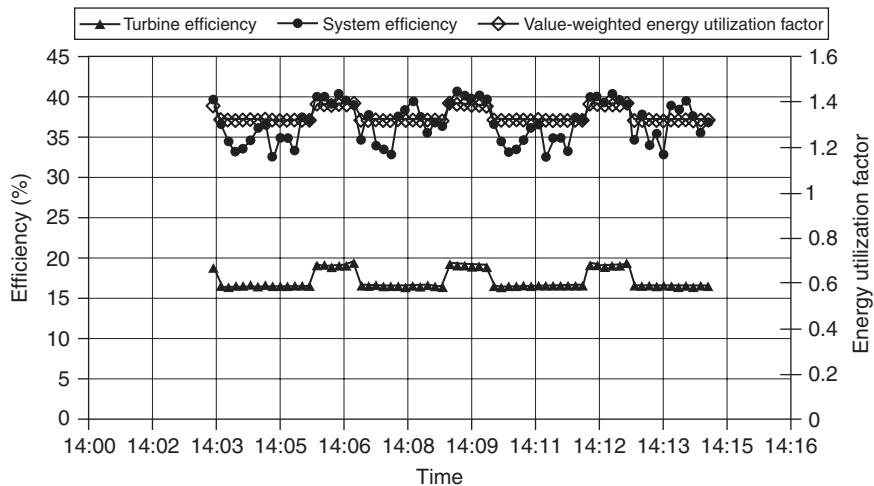


FIGURE 17-2 Trends of turbine, cooling tower, and system efficiency, cooling tower utilization efficiency and value-weighted fuel utilization factor.

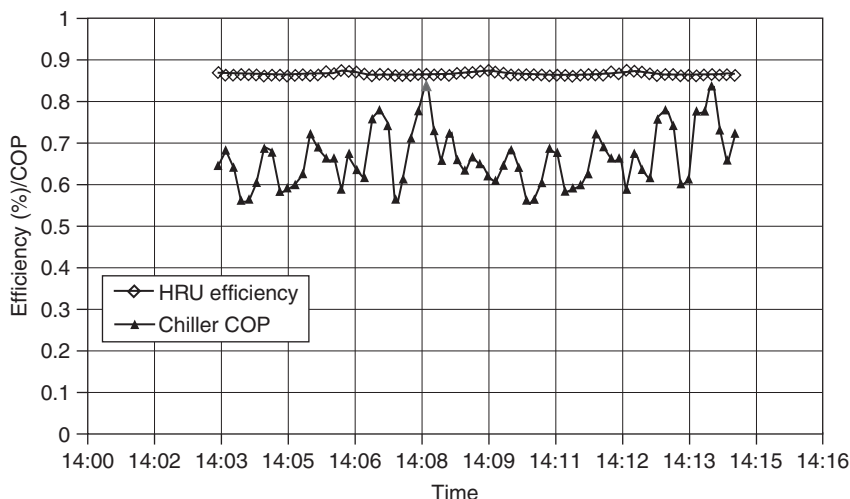


FIGURE 17-3 Trends of HRU efficiency and COP of the absorption chiller.

CHP Performance Monitoring and Commissioning Verification Algorithm Deployment Scenario

This section addresses how the algorithms presented in the previous sections could be used in start-up and operation of a CHP system. The algorithms could be deployed in a number of different ways, including embedding them in controllers used to control the CHP components or developing a software application that runs on an independent plant computer platform. In this section, we describe a hypothetical deployment scenario in which the algorithms presented in earlier sections for CHP system monitoring and CxV are deployed to monitor and perform verification of start-up operations of a CHP plant.

The major elements of the CHP software application, are (1) a process to record sensor and control data from the CHP system; (2) a database to store the information; (3) a set of processes to preprocess the raw data (e.g., perform quality control, convert units, and aggregate data over time) and post the data back into the database; (4) a set of algorithms that are used to process the raw data to generate useful results; (5) a process that allows users to configure the CHP application and view configuration settings using a Web browser; and (6) a process that enables users to view the results in a Web browser.

While many of the implementation details are not discussed here, the following example is provided to illustrate how these algorithms could be deployed in actual practice. The algorithms provide the basis for tools that could be developed by manufacturers and third-party service providers. We anticipate that most tools developed in the future will be Web-based, so users of the tools will not need to install special software on their computers to configure the CHP application or view results. We anticipate that the raw data from various sensors and control points in a CHP plant are recorded in a database periodically (e.g., at 1 minute to 15 minute intervals); these data are then periodically preprocessed to generate additional (derived) data. The preprocessed data, for example, can be simple aggregations of sub-hourly data into hourly

values or calculations of derived engineering quantities (e.g., the COP, which is calculated using data from a number of primary sensors). It can also involve calculation of moving averages for certain measured quantities. The results of preprocessing are written back into the database. A set of algorithms, either continuously or periodically, analyzes both the raw and preprocessed data to generate useful information and post it back to the database. Users can then review the results or the system can provide alarms and suggestions to users through the Web browser.

CHP Performance Monitoring and Commissioning Verification Application Scenarios

In this section, we describe two hypothetical scenarios in which the algorithms presented in the chapter for CHP system monitoring and CxV are used in the start-up and operation of a CHP plant. The plant in this scenario uses a small natural gas-fired turbine as the prime mover with heat recovered from the exhaust to produce hot water. The hot water is used to fire an absorption chiller to provide cooling to a commercial building. A duct burner fired with natural gas is used to provide supplemental heat to the absorption chiller to meet building needs when cooling demand exceeds the capacity provided by the exhaust alone.

The CHP system is rated at 1 MW_e and produces about 1.7 MW_{th} of useful heat, which is available to the absorption chiller in the form of hot water at 257°F (≈ 125°C). Chilled water is supplied by the chiller at approximately 45°F (≈ 7°C) for use in cooling a commercial building. The COP (coefficient of performance) of the absorption chiller is about 0.70. The local price of natural gas to fuel the turbine and auxiliary duct burner is about \$1.00/therm (≈ \$9.50/GJ), and the price of electricity is \$0.10/kWh. The value of the cooling provided (based on comparison to cooling from a vapor-compression air conditioner and electricity at the price indicated) is approximately \$0.035/kWh_{th} (\$10.25/million Btu) of cooling.

A scenario describing the use of monitoring is presented first and is followed by a scenario illustrating the use of the commissioning verification process.

The monitoring system provides continuous streams of data for the following efficiency and effectiveness metrics:

- Value-weighted energy utilization factor, EUF_{vw}
- System fuel utilization efficiency, η_f
- Electric generation efficiency, η_{EE}
- Heat recovery unit effectiveness, ϵ_{HRU}
- Absorption chiller coefficient of performance, $COP_{AbChiller}$
- Cooling tower efficiency, η_{CT}
- Cooling tower electric utilization efficiency, $\eta_{CT,elec}$
- Cooling tower pump efficiency, η_{pump}

In addition, the system provides real-time monitoring for the following conditions:

- Fuel input rate to the turbine, $\rho_{Fuel} \dot{v}_{Fuel,Turbine} LHV_{Fuel}$
- Auxiliary fuel input to duct burner, $\dot{v}_{Fuel,Aux}$

- Exhaust gas temperature, $T_{\text{Turbine, ex}}$
- Rate of useful heat output, Q_{th}
- Chilled water supply temperature, $T_{\text{evap, w, o}}$
- Chilled water return temperature, $T_{\text{evap, w, i}}$
- Temperature of water entering the HRU, $T_{\text{HRU, w, i}}$
- Temperature of water leaving the HRU, $T_{\text{HRU, w, o}}$
- Exhaust gas temperature leaving the HRU, $T_{\text{HRU, ex, o}}$
- Current electric power output, W_{elec} (kW)
- Average daily electric energy output, $\int_0^{24\text{hours}} W_{\text{elec}} dt$ (kWh/day)
- Average electric power output over the last n hours, $\int_{t-n}^t W_{\text{elec}} dt/n$ (kW)
- Daily average hourly electric power output, $\int_0^{24\text{hours}} W_{\text{elec}} dt/24$ (kW)
- Cooling tower water inlet temperature, $T_{\text{CT, w, i}}$
- Cooling tower outlet temperature, $T_{\text{CT, w, o}}$
- Cooling tower approach, $T_{\text{CT, w, o}} - T_{\text{wb}}$
- Cooling tower range, $T_{\text{CT, w, i}} - T_{\text{CT, w, o}}$

The system monitors these performance parameters and conditions and provides alarms to the operators when conditions deviate significantly from baseline values. A hypothetical sequence of values is shown in Table 17-3 to illustrate a scenario, where monitoring of these parameters assists operators in detecting and correcting a system performance problem much quicker than would be possible without such a monitoring system. Thirty minutes has been used for illustrative purposes, and monitoring of an actual system would likely be done using a much shorter time interval than the 30-minute interval used in the table.

Conditions at 13:00 are consistent with those for several immediately preceding time steps (values not shown in the table), and the system is running properly. At 13:30, deviations for a few performance variables ($\text{COP}_{\text{AbChiller}}$, η_{CT} , Q_{th} , and $T_{\text{CT, w, o}}$) from the values at 13:00 can be seen, but their magnitudes are so small that no problems are apparent. In fact, these deviations are all within the range of normal variations likely to be observed during normal, fault-free, operation.

At 14:00, some substantial changes in performance variables are evident. The value-weighted energy utilization factor has decreased by about 4.5 percent (from 1.12 to 1.07), not enough to be alarming by itself, but if this persists over the long run, fuel cost increases will be substantial. The fuel utilization efficiency has also decreased from 59 to 54 percent, and the effectiveness of the heat recovery unit has decreased from 63 to 54 percent (i.e., by 14 percent), tending to indicate that something is wrong with the heat recovery. The electric generation efficiency has not decreased, but the COP of the chiller has dipped from 68 to 60 percent, and most alarmingly, the overall cooling tower efficiency and electric-utilization efficiency of the cooling tower have decreased by 26 percent (from 70 to 52 percent) and 50 percent (from 7.0 to 3.5), respectively. The output of the chiller has also decreased from 1180 to 1000 kW_{th}. These observations direct operator attention immediately to the cooling tower, which clearly has some sort of

Time	13:00	13:30	14:00	14:30	15:00
EUF_{vw}	1.12	1.12	1.07	1.12	1.12
η_F	0.59	0.59	0.54	0.59	0.59
η_{EE}	0.27	0.27	0.27	0.27	0.27
ε_{HRU}	0.63	0.63	0.54	0.62	0.63
$COP_{AbChiller}$	0.70	0.68	0.60	0.68	0.70
η_{CT}	0.71	0.70	0.52	0.68	0.71
$\eta_{CT, elec}$	7.0	7.0	3.5	6.5	7.0
η_{Pump}	0.65	0.65	0.65	0.65	0.65
$Q_{Fuel,turbine}$ $= \rho_{Fuel} \dot{v}_{Fuel,Turbine} LHV_{Fuel} \text{ (kW)}$	3703	3703	3703	3703	3703
$Q_{Fuel,aux}$ $= \rho_{Fuel} \dot{v}_{Fuel,AuxiliaryHeat} LHV_{Fuel} \text{ (kW)}$	0	0	0	0	0
$W_{elec} \text{ (kW)}$	1000	1000	1000	1000	1000
$Q_{th} \text{ (kW}_{th})$	1190	1180	1000	1185	1190
$T_{Turbine, ex} \text{ (}^{\circ}\text{F)}$	620	620	620	620	620
$T_{evap,w,o} \text{ (}^{\circ}\text{F)}$	45.0	45.0	48.0	46.0	45.0
$T_{evap,w,i} \text{ (}^{\circ}\text{F)}$	55.0	55.0	58.0	56.0	55.0
$T_{HRU,w,i} \text{ (}^{\circ}\text{F)}$	239	239	247	241	239
$T_{HRU,w,o} \text{ (}^{\circ}\text{F)}$	257	257	258	257	257
$T_{CT,w,i} \text{ (}^{\circ}\text{F)}$	95	96	102	96	95
$T_{CT,w,o} \text{ (}^{\circ}\text{F)}$	80	81	88	82	80
$T_{wb} \text{ (}^{\circ}\text{F)}$	74	75	75	75	74
$T_{CT,w,o} - T_{wb} \text{ (}^{\circ}\text{F)}$	6	6	13	7	6
$T_{CT,w,i} - T_{CT,w,o} \text{ (}^{\circ}\text{F)}$	15	15	14	14	15

TABLE 17-3 Sequence of Monitored Values for Performance Parameters and Physical Conditions

problem. Looking at some of the measured variables for the cooling tower reveals that the temperatures of the water entering and leaving the cooling tower have increased by 6°F and 7°F, respectively, further supporting the operator’s conclusion that the cooling tower has developed a problem, is not rejecting heat effectively from the condenser water, and is using more electricity to run its fans (known because the condenser pump efficiency has not degraded, leaving only the fans to have caused this increase).

In response to these observations, the operator sends two technicians to inspect the cooling tower. Upon inspection, the technicians find a large piece of cardboard from some sort of container for shipping a large appliance or machine lodged against the air-inlet openings to the cooling tower. The cardboard appears to be blocking the flow of air induced by the fans. The technicians surmise that shortly after noon, when a violent

wind storm blew through the area, cardboard debris from nearby trash containers must have blown up against the cooling tower and become lodged. To compensate for reduced flow area, the cooling tower controller began running additional fans, increasing the electric power consumption of the cooling tower and causing the observed substantial decrease in cooling tower electric efficiency, $\eta_{CT,elec}$, but with little effect on cooling of the cooling water. As a result, the cooling tower performance decreased significantly. The technicians remove the cardboard and dispose of it properly. They return to the control room. The entire inspection and repair took about 15 minutes.

Fifteen minutes later at 14:30, the effect of removing the cardboard is clearly apparent in the monitored data. The fuel utilization efficiency has increased back to 59 percent. The heat recovery effectiveness is nearly up to its preincident level at 62 percent, and the cooling tower efficiency and electric utilization efficiency have both nearly fully recovered to preevent levels, now being 68 percent and 6.5, respectively. The chiller output is also close to fully recovered at 1185 kW_{cooling}. The cooling tower inlet water and outlet water also have nearly returned to preevent temperatures. By 15:00, all parameters indicate full recovery, concluding our performance monitoring scenario.

Without the level of monitoring indicated in this scenario, the cooling tower problem would likely have persisted for some time, possibly a day, a week, or even longer. Fuel use and costs would have increased, cooling-output would have remained low, and equipment would have run longer and harder. Detection of many different operation faults and causes of degradation are possible with close monitoring. The key is to provide information in real-time or short-time intervals to enable plant operators to continually know the state of the CHP plant, its major systems and components.

To illustrate application of the capabilities provided by the CxV algorithms, we provide the scenario that entails using hot water to fire an absorption chiller for commercial cooling. In this case, the scenario focuses on the performance of the prime mover, a small turbine, and the electric generator to produce electricity and waste heat in the exhaust gases as a by-product.

The system manufacturer has rated the turbine at 1 MW_e at which it will produce 1.7 MW_{th} of heat captured in hot water at 257°F (125°C). The hot water is produced by a matched heat recovery unit. When fired at 80 percent of capacity, the manufacturer's specification indicates that at an outdoor air temperature of 60°F (~15.6°C), the turbine generator will produce 800 kW_e and 1.36 MW_{th} of heat in hot water at 257°F (125°C). Upon initial start-up of the system, after allowing time for the system to reach steady operation at 80 percent of full firing rate, the CxV system reports the following:

- Electrical output, W_{elec} , is 800 kW_e, which is within the expected range for the current outdoor temperature and fuel firing rate.
- Thermal output is 1100 kW_{th}, which is below the expected range.

Using its diagnostic capabilities, the CxV system also reports that

- Turbine exhaust-gas temperature, $T_{Turbine,ex}$, is 670°F (354°C), higher than expected (which is 620°F or 327°C)
- Hot water temperature leaving the HRU, $T_{HRU,w,o}$, is 302°F (150°C), higher than expected (which is 257°F or 125°C)

and recommends checking control of the variable-speed water circulation pump, which appears to be pumping at a lower rate than necessary.

A technician checks the pump controller, finds that the operating range and calibration are not correct, and replaces the table for these variables in the control code with a table from the manufacturer based on testing the pump in the system (before initial firing). Upon replacing the table and waiting for the system to reach steady operation, the CxV system reports that operation is as expected. This aspect of operation of the CHP plant has now been corrected and verified by the CxV system.

Summary

In this chapter we provided information on why sustaining operations of CHP is important as well as algorithms for CHP system performance monitoring and commissioning verification (CxV), including system-level and component-level performance metrics. We also discussed how verification of commissioning can be accomplished by comparing actual measured performance to benchmarks for performance provided by the system integrator and/or component manufacturers.

The CxV scenarios also showed how the results of these comparisons can be automatically interpreted by software to provide conclusions regarding whether the CHP system and its components have been properly commissioned and where problems are found, guidance can be provided for corrections. Application of algorithms to CHP laboratory and field data has also been illustrated, and the chapter concludes with a discussion on how these algorithms can be deployed. Monitoring and verification of performance as illustrated in this chapter will become increasingly important as fuel prices increase, CHP systems become more widely used, and concern with sustainability of our energy systems increases.

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Sustaining CHP Operations

Lucas B. Hyman

Milton Meckler

As described in the preceding chapters, there are a variety of factors and requirements that work together for sustainable on-site CHP operations. CHP plant management and plant operators need to thoroughly understand: the CHP plant, the CHP plant systems, and the CHP plant equipments; CHP plant operating strategies; utility rate structures; energy markets and energy purchase strategies; utility metering, bookkeeping, and billing; and, last, but certainly not least, proper plant operation and maintenance. CHP plant consultants need to understand the above as well.

As the old adage states, “one cannot manage what one does not measure,” therefore, sustainable CHP operations should have extensive metering and monitoring system as part of the plant control system. With good metering and monitoring, the cost of production for all CHP-produced utilities as well as various CHP metrics can be calculated and trended, as later discussed in this chapter, making optimizing operations and performance diagnostics easier.

Sustainable on-site CHP systems value their plant operators, invest in their training, and have mechanisms in place to facilitate feedback and good, open communication to improve plant operations. CHP plant operating strategies and their requirements/consequences/costs need to be fully analyzed and understood by all concerned. Also, resources need to be retained and expended to maintain the long-term sustainability of the CHP plant. Insurance requirements must also be carefully considered and met to ensure sustainability. Finally, CHP plant management needs to share their success story with others in order to promote the use of CHP, which maximizes total plant fuel efficiency, minimizes primary fuel consumption, minimizes overall pollution, and when properly planned, designed, and constructed can provide an attractive return on investment when compared to the conventional business-as-usual (BAU) case of buying utility power and burning fuel in a boiler to produce heat.

Understanding the CHP Plant

It can be challenging to sustain CHP operations if those responsible for managing and operating a CHP plant do not fully understand plant operations. Understanding the CHP plant operations begins by understanding the function and construction of each

individual piece of plant equipment. CHP plant personnel should be able to discuss how individual pieces of equipment and the main components that make up that equipment function. Various pieces of plant equipment are tied together in plant systems, and CHP plant personnel should

- Trace out all plant systems (i.e., follow the piping through plant from start to finish).
- Draw, from memory, a schematic diagram of each plant system showing all major equipments and key system components including all major valves.
- Discuss with the lead operator each piece of equipment in each system and how the system functions efficiently as part of the overall CHP plant.

The various CHP plant systems combine to form a working CHP plant that often has various equipment strategies and equipment operational choices. The equipment/system operating choices can be analyzed and understood and CHP plant personnel should have this information in order to make good economical decisions (e.g., operate the duct burners and steam turbine generator during the summer on-peak periods, or take the electric-drive chillers off-line and use the absorption chillers during the on-peak period).

Sustainable on-site CHP operations require a team effort by CHP plant management, plant operations, and often by outside consultants (engineering, energy-purchase, financial) with each team member playing an important role. While each team member has a role to play and a certain level of expertise, all CHP plant team members should be familiar with all the basic aspects of the operation and maintenance of the CHP plant.

The typical main goal of the sustainable CHP plant is to maximize the return on investment (ROI) in the plant itself, to payback investments, to fund plant operations and maintenance, and hopefully to provide for a reserve fund for equipment replacement. The ROI is maximized, when the annual CHP plant utilization is maximized, for example, when the electric generators are fully loaded and the waste heat-generated steam is fully consumed, for example. Assuming that the CHP plant was properly sized and configured for the facilities varying electric and thermal load profiles, CHP plant output is maximized by maintaining a high plant availability, which results from good operation and maintenance procedures, but is also very much a function of equipment quality and plant design.

The ROI is also maximized by minimizing plant operating costs, with fuel costs usually being the major cost driver. Depending upon CHP plant location, fuel purchase options vary from "the only option is to buy fuel from the local utility" to "buying different term (spot, short-term, long-term) fuel contracts on the open market." Knowledge, experience, expertise, and some luck are required to minimize fuel costs when buying fuel in the futures markets. CHP plant management must make decisions with consequences based on unknowable futures. Will fuel prices rise or fall, and if so, by what escalation or de-escalation rate? Other decisions must be made: What is the appropriate breakdown between spot-market, short-term, mid-term, and long-term fuel contracts? Is it better to lock in (or hedge) using a guaranteed long-term, known fuel cost, or take a chance on saving money in the spot market should fuel prices fall with the chance that one could have to pay more, possibly substantially more, for their fuel than they would have otherwise had to pay? Some facilities have a full-time energy manager to work on the above issues, while other facilities hire outside consultants for professional advice.

Note that fuel cost is also minimized by maximizing plant operating efficiency and minimizing energy use per unit of production (e.g., Btu/kWh, kW/ton) which is affected by a variety of factors as discussed under “Operating Strategies” in this chapter. Labor costs can also be a significant cost of operating a CHP plant if, for example, full-time licensed steam plant operators are required.

Maximizing the ROI many times involves properly metering and billing for CHP plant-generated services. Therefore, CHP plant management and staff need to understand the basics of the number, functions, and types of usage meters and how the information on those meters is translated onto customer utility bills, as applicable.

CHP Data Gathering

As noted, one of the critical requirements for a sustainable CHP plant is the ability to gather sufficient information/data in order to (1) properly meter and bill for CHP services, and (2) monitor and trend performance in order to help maximize performance. The first step begins with data gathering, which can be automated as part of the plant control system.

Metering

CHP systems are often part of a district energy system, and, in many cases, customers are billed for their electricity and thermal usage. Meters are typically used to measure the amount of usage of electricity, steam, condensate, heating hot water, domestic hot water, and chilled water, for example. Measurement of electricity typically includes both a measurement for usage and for demand. Electricity meters are not only required for each individual building, but also required to capture generator output, parasitic losses, purchased power, power sold to the grid (if applicable), and individual system/equipment consumption (e.g., chiller power in order to measure kW/ton). As with many types of fluid meters, steam meters need to be located with the proper upstream and downstream straight-run diameters to function properly. Steam meters need to record total production, parasitic losses, as well as individual building consumption. Condensate meters should also be installed, and customers charged on their net consumption (Btu) obtained by computing the total energy consumed equal to the energy (enthalpy) supplied in the steam minus the energy returned in the condensate. In this way, condensate that is not returned to the CHP plant is accounted for and charged. Finally, by employing meters now available with significant technology enhancements, for example, smart meters compatible with automated billing systems and wireless technology that allow meters to be read remotely, significant time and costs can be saved.

Monitoring

In addition to metering, the CHP plant's power output and the various power usages, the CHP plant control system, as noted, needs to monitor and record total thermal production (steam/hot water), all thermal usage, and any chilled water production. The monitoring and control system should also monitor and record all of the flows and temperatures and pressures listed in Chap. 17. In addition to alarms and control, the plant monitoring data should be used to compute equipment and system efficiencies for use by plant operations to better track CHP operations, to help with plant troubleshooting, and to provide CHP plant optimization feedback. Monitoring points and calculated quantities can also be trended to help in plant operating decisions.

CHP Data Analysis

Given the plant data, plant personnel and/or outside consultants can analyze CHP plant operations. Important information can be gleaned directly from the basic data, and there are a number of metrics that can be employed to analyze CHP plant operations. Results of data analysis can be benchmarked against other facilities and other plant operating options in order to draw comparisons, contrasts, and conclusions.

Review of basic data obtained directly provides important information regarding:

- Total electricity generated
- Total heat produced
- Tons of cooling generated
- Amount of fuel consumed
- Electricity sales
- Thermal sales (heating and cooling)
- Key plant operating parameters, for example, temperatures, flows, and pressures of steam and condensate systems, hot water systems, chilled water systems, and condenser water systems to gain a better understanding of their impact on overall plant efficiency

Metrics

In addition to the basic CHP/facility data, important metrics (performance indicators) can be developed/calculated using the raw data taken and recorded from the CHP plant in order to better understand the plant operations, and can provide guidance toward more efficient sustained plant operations. Care should be taken not to draw broad conclusions or to make false assumptions regarding individual metrics. Key CHP metrics include the following:

- Cost per net kilowatthour generated
- Cost per therm [or Btu, or kilojoule (kJ)], or other appropriate unit of heat recovered]
- Cost to produce CHP facility services versus the BAU case
- Amount of money saved by employing CHP versus the conventional BAU case
- ROI
- Overall CHP efficiency (which is equal to the sum of the net power output and the recovered heat divided by the total fuel input)
- FERC efficiency in the United States (the recovered heat is multiplied by 0.5 in the CHP efficiency calculation mentioned above)
- CHP heat rate (which is equal to fuel input per power output measured in Btu/kWh or kJ/kWh)
- Electrical generation efficiency (which is equal to net power output divided by fuel input in consistent units)
- Value-weighted energy utilization factor [which is equal to the value of the power plus the value of all thermal uses divided by the fuel input (see Chap. 17)]

- CHP electrical effectiveness (which is equal to the net power output divided by the difference between the fuel input and the total recovered heat)
- Amount of avoided fuel purchases
- Amount of avoided pollution

Calculating and comparing the cost to produce individual facility services (e.g., electric power, steam, chilled water, or domestic hot water) on a per unit delivered basis (e.g., kWh, therms, or ton-h) provides CHP stakeholders with key information upon which to base important decisions. Utility production unit costs are also required in order to calculate the overall CHP plant savings described below. The CHP plant utility services provided by the CHP plant, of course, depend upon the type of the CHP plant itself. Some CHP plants, for example, provide: electricity at multiple distribution voltages, steam at multiple distribution pressures, high-temperature hot water, heating hot water, domestic hot water, chilled water, compressed air, and treated water such as deionized (DI) and reverse osmosis (RO); while other CHP plants just provide electricity at a single voltage and steam at a single pressure (or heating hot water at a single temperature). Whatever utilities are provided by the CHP plant should be fully metered and all costs accounted for. Most purchased utilities have some time-of-use or tiered consumption rate schedule that must be factored into the CHP plant's calculations and analysis. For example, the cost to generate electric-power-produced chilled water will likely be less expensive at night versus during the day (unless the facility is on a flat tariff rate schedule), while the value of CHP-produced power will likely be more valuable during the day than at night. Typical unit cost comparison metrics include

- CHP cost of kilowatthour versus utility kilowatthour cost
- CHP cost of unit of heat (e.g., pounds of steam, Btu, therms, or kJ) versus local boiler-produced unit of heat
- CHP cost of generated cooling (e.g., Btu, ton-h, kJ) versus local chiller

In order to compare unit costs, the total cost of individual CHP-provided services must be calculated and determined. Cost analysis can sometimes be challenging and results can shift depending upon how costs are allocated. For example, how to allocate fuel costs between electricity and heat production is an important question. This follows since how fuel costs are allocated between CHP plant generated utilities will affect the unit cost analysis and metrics results. Similarly, how to account for labor costs between the various CHP plant-supplied utilities is also an important question, since not all equipment requires equal supervision. For example, a high-pressure HRSG probably has mandated 24-hour-per-day licensed operator requirements, while an electric-drive centrifugal chiller with a unit control panel only needs to be checked periodically. Comparing the cost to provide CHP-generated utilities versus the BAU case should show that a positive rate of return is being achieved, that is, the cost to generate CHP utilities should be less than the BAU case. Note that achieving the lowest unit cost for delivered utilities does not necessarily indicate or guarantee that the maximum ROI is being achieved (e.g., there might be a case where unit costs are greater but a higher total CHP plant revenue is achieved for the same fixed costs yielding a better return).

The total net amount of money saved by employing CHP versus the conventional BAU case can offer a realistic estimate of CHP plant's financial performance and is determined by calculating and comparing the cost of electricity and local boiler consumed natural gas (NG), if purchased from the local utility, versus the cost of on-site CHP electric power generation and recoverable waste heat utilization. Cost comparisons may be over any time period from 15 minutes, hourly, daily, monthly, to annually, as appropriate.

Another important metric to calculate and monitor is the overall CHP plant thermodynamic efficiency (or fuel utilization efficiency), which is equal to the quantity of net CHP plant power output (gross power output less parasitic electric loads needed to operate the CHP plant) plus net CHP plant thermal output (gross thermal output less parasitic thermal loads needed to operate the CHP plant) divided by the total quantity of CHP plant fuel input, all in consistent units. By monitoring CHP efficiency, operating personnel can have the benefit of feedback regarding operating conditions and strategies, can see trends develop, and can try to maximize CHP operating efficiency, which minimizes fuel consumption and provides both financial and environmental benefits. Note that CHP efficiency can be calculated over any time period.

Another important efficiency metric is heat rate, or the amount of fuel required to produce one unit of power (Btu/kWh). A lower heat rate indicates a more electrically efficient machine, and given the heat rate, the electric power generation efficiency (another efficiency metric) can easily be calculated, monitored and trended, and can provide key feedback regarding the efficiency of prime movers. Note that just because the facility has achieved a low heat rate (i.e., high electrical power generation efficiency) does not mean that the CHP facility has achieved a high overall plant thermodynamic efficiency; and a high heat rate does not mean that the CHP plant has a low overall thermodynamic efficiency since the CHP plant could recover and use a large percentage of the waste heat.

One challenge when considering overall CHP efficiency is that it treats the electric power and the thermal output equally. However, electric energy typically has a higher exergy value than thermal energy. As discussed in Chap. 17, another important metric that can provide a useful performance indicator regarding CHP plant operation is the value-weighted energy utilization factor (EUF_{vw}). EUF_{vw} is equal to quantity of the value of the net power produced plus the value of the thermal energy recovered divided by the cost of the fuel input. The EUF_{vw} represents the marginal value-to-cost ratio and should be greater than 1. A EUF_{vw} less than 1 indicates that the CHP plant costs more to fuel than the corresponding value of the heat and thermal energy recovered. The value of the power produced is equal to the net kilowatthours generated multiplied the cost per kilowatthour. While the value of the generated steam or hot water is equal to the net thermal output times the cost per unit of heat (e.g., per Btu). The cost to produce CHP-related services is calculated as apart of determining CHP unit production costs discussed above and in further sections below. Typically, the goal of CHP plant personnel is to maximize the EUF_{vw} wherever possible.

CHP electrical effectiveness, which equals the net power output divided by the difference between the fuel input and the total recovered heat provides another metric that recognizes the value of CHP plant electric power output. The more heat that is recovered for a given power output, the closer CHP electrical effectiveness approaches a value of 1.0 as all energy not converted to power is recovered and beneficially used.

Another metric that is important is the amount of avoided greenhouse gas (GHG) produced based on the fuel saved, which is equal to the calculated amount of fuel that would have been used in the BAU case minus the fuel that is used by the CHP plant. The BAU amount of fuel can be calculated by the following formula:

$$\text{BAU fuel consumption} = \text{power produced/local grid generation efficiency} \\ + \text{the sum of all heat recovered/heat production efficiency}$$

Typical grid generation efficiency is about 32 percent and typical natural gas-fired boiler efficiency is about 80 percent. Given the amount of fuel saved, the amount of CO₂ eliminated can be calculated as described in Chap. 7.

Finally, it should be noted that no single metric can be used to accurately model CHP plant operations, and each metric has its limitations. For example, heat rate can only be used to approximate electric power generation efficiency, but cannot account for heat recovery. Similarly, CHP efficiency while capturing the overall thermodynamic process and fuel utilization efficiency cannot account for the added value of the generated electricity and recovered heat. The EUF_{vw} does not account for labor costs, debt service, and reserve fund costs. ROI calculations do not account for positive externalities such as pollution reduction. Each metric does provide important feedback, which when trended and taken together with other metrics can provide important plant operating guidance.

Benchmarking

Benchmarking, when employed together with the above-described metrics, allows CHP plant personnel to compare their CHP plant cost to generate a kilowatthour or a pound of steam (with other similar CHP facilities) as well as their energy use per unit area, which can depend on the type of facility, facility construction, facility location, season, weather, and occupancy schedule. Benchmarking can sometimes be misleading. For example, a CHP facility with a favorable low energy use per square foot compared to other CHP facilities with higher values may be the result of a more benign climate compared to others located in more extreme microclimates, and/or the result of shorter operating hours than other facilities in the CHP plant group being compared against.

Maintaining an Issues Log

In order to maintain or sustain efficient operations, CHP plant management should set up formal procedures to capture and document all relevant operational issues, changes to controls, and any plant operating strategies. The *issues log* (which can either be electronic, hard copy, or both) should also provide a chronological format to record all trouble calls, equipment trips, alarms, likely cause(s), and resolution(s). The log book should also document any systems and/or equipment, and/or controls that have been placed in hand, bypassed, and/or overridden as well as any equipment that is out of commission. The log should also provide space to record operator-requested changes to programming/operating strategies, the reason for the change, and the resolution of the request. Finally, and importantly, operators must be given a way to provide suggestions for improvement so that CHP plant operations can remain optimized.

Billing

For those owner-operators who charge customers for CHP plant-generated utilities, accurate and clear billing is important in sustaining efficient CHP operations as it provides the funding for operations, maintenance, and reserve funds necessary for future equipment replacement. Billing best practices are those practices that are

- Transparent
- Auditable
- Fair (reasonable)
- Easy to follow
- Follow generally accepted accounting principles (GAAP)
- Account for all costs (including capital)

Following these best practices, all costs associated with producing power, steam, and chilled water are appropriately accounted for and assigned, including

- Fuel
- Operating staff
- Maintenance
- Purchased power/standby charges
- Administration
- Water/chemicals
- Supplies
- Permitting/source testing
- Debt service
- Depreciation and/or reserve fund

Whenever possible, cost should be assigned to the applicable individual utility service. Work on the electrical generator should be assigned to the cost of producing electricity. If the cost is strictly for providing heat, assign the cost to the cost of generating heat. If a cost cannot be allocated to either electricity or thermal production, the cost should be shared between both utilities. Different methods exist to properly allocate costs to shared utilities. One method is simply to assign half of the costs to electricity service and half of the costs to thermal energy recovered. Other cost splits may have more merit including dividing the costs proportionally to match the actual proportional value of the utilities.

Parasitic loads should also be computed in order to determine net output. Examples of parasitic loads include

- Natural gas compressors
- CHP plant pumps
- Cooling tower fans
- Water treatment systems
- Deaerating (DA) tank (steam)

In addition to the parasitic loads, system losses must also be evaluated, including

- Electrical distribution system
- Steam distribution system
- Condensate return system
- Hot water system
- Chilled water system

With operating costs and losses known, appropriate billing rates can be developed. The bill itself should be easy for consumers to follow and should include relevant metrics to indicate efficiency such as kilowatthour per square foot, utility usage for the same time period in previous years.

Operating Strategies

The number and type of possible plant operating strategies usually depends on the CHP plant size versus facility electric and thermal loads; the nature and type of available CHP plant equipment options; the number and size of various CHP units available; and the available CHP plant features such as duct burners. A modern, technologically advanced, robust, fast-acting, adaptive control system capable of calculations and automated decision making can be very helpful, if not essential, in implementing various operating strategies. While it is beyond the scope of this chapter to discuss/detail every operating strategy of a CHP plant, this section attempts to provide overall guidance on how to think about and how to develop appropriate sustainable operating strategies for the site-specific CHP plant.

Operating strategies will depend upon the CHP plant size versus facility electric and thermal loads, with thermal loads understood to include all heating, cooling, and thermal-to-power loads. For example, if the CHP plant has been sized to be base loaded electrically and thermally 100 percent of the time, the operating strategies will solely be focused on maximizing equipment and system efficiencies, as previously described, and minimizing plant parasitic losses in order to help minimize CHP fuel consumption. On the other hand, the CHP plant may be sized to track facility thermal loads such that declining thermal loads will require decisions regarding thermal use, power production, and related prime mover operation. Furthermore, plant operating strategies depend on the nature and type of available equipment options, and a matrix of all available equipment options, may need to be developed. The matrix should show all plant equipment options listing each and every equipment/system choice. For example, equipment/system choices might include: operate one engine-generator, operate two engine-generators, fire the duct-burner, operate the turbine inlet cooling system, operate the steam powered chiller(s), operate the electric-drive chiller(s), operate the steam turbine generator(s), and transfer heat either directly or via plant heat exchangers to various thermal loads with each load or system heat exchanger listed as a separate line item in the matrix. The matrix should include the available number of units, the number of CHP modules, the number of chillers, the number of pumps for each system along with marginal operating costs, values, and even relative values (e.g., on-peak operational savings or cost) that can help determine good equipment choices/operating strategies.

Financial pro forma models can also be created to calculate/estimate total and marginal cost, value, and amount of money saved for each piece of equipment/system operated. Cost and values will, of course, be affected by utility time-of-use rates, seasonal differences in utility costs, as well as by the cost of fuel (which can change depending upon season/purchase agreements/terms), all of which needs to be factored into account in order to better understand equipment/system operating choices and their resultant cost/revenue implications/consequences.

With respect to the big picture, general operating strategies are as follows:

- Maximize net revenue
- Minimize heat rate, maximize CHP plant efficiencies, minimize parasitic plant power consumption, and minimize all losses
- Minimize carbon footprint

Maximizing net revenue (value) is probably the most common strategy employed by CHP owners and operators, makes good financial sense, and often incorporates other features in the list above. Under the maximizing value strategy, efforts are made to maximize revenues (generate and sell all CHP services possible given fixed-plant resources even if the generation/production is not the most efficient possible and degrades overall CHP plant efficiency metrics) and to minimize costs (efficiency improvements can be an important factor) thereby to maximize net revenue. Equipment options/system operations are generally selected based on maximizing net revenue. For example, at a given time, a choice might need to be made whether to operate a steam absorption chiller or an electric-drive chiller, and a matrix, as described earlier, can provide answers to what is the lowest-cost equipment to operate. In this case, for example, it may be cost-effective to operate the absorption chiller during the on-peak period but not during the off-peak period. Under this hypothetical case, a consideration may be whether to use heat recovery produced steam in a steam turbine generator to produce additional power, or to use the steam instead in an absorption chiller to produce chilled water for space cooling. Another option may be to produce additional steam in the duct burner. Also, with a CHP plant, there may be times when a use for the recovered waste heat overrides/changes cost calculations.

For example, if the heat is going to be dumped it may need to be used to meet regulations and essentially becomes free. Each option should be analyzed modeled in order to provide CHP plant personnel and control system the information needed to maximize net revenue. In the absence of unit production cost analysis figures, it may be best to use recovered heat in the order of highest value to lowest value which is often additional power, cooling, and heating, respectively.

Other operating strategies which are usually incorporated into the above maximizing net revenue strategy is to minimize parasitic and distribution losses, to maximize CHP plant efficiencies, and to minimize prime mover heat rate, which, of course, are all inextricably linked together. As with any energy project, reducing waste is step 1, minimizing facility loads is step 2 (daylighting, more efficient lighting, building insulation, more efficient windows, etc.), and minimizing CHP plant losses, where possible, should be studied, reviewed, and implemented on an ongoing basis as step 3. A common loss occurs in the condensate system where condensate is not returned from buildings to the plant and/or where heat losses occur in condensate piping, losing energy. While another common example is poorly maintained steam traps that often leak by wasting enthalpy

(the steam traps let steam pass through to the condensate system). All piping should be well maintained, well insulated, and free from leaks. Plant pumps should be selected and operated to minimize pumping horsepower. Most importantly, pumping horsepower can be minimized by maximizing hydronic system delta-T (difference between supply and return temperatures). Of course, many losses are set by the design and construction of the CHP plant itself, for example, pipe sizes, inlet-air duct size, and inherent pressure drops are set.

Improving CHP plant efficiencies including chiller plant efficiencies are important and interesting subjects worthy of a separate chapter or even a separate book by themselves. Overall CHP efficiency as well as electric generation effectiveness are maximized by recovering and beneficially using as much of the waste heat as possible. Dumping of heat must be avoided or minimized. The challenge with improving CHP plant efficiencies is that equipment/systems are interrelated and the operations of one system, for example, effects the operations of another system. For example, higher flow, colder condenser water allows electric-drive chillers to operate more efficiently requiring less motor horsepower. But providing higher condenser water flows requires higher condenser water pump power (for a given system), and providing colder condenser water requires higher cooling tower fan horsepower (for a given wet-bulb temperature). The question is whether the chiller horsepower savings are more than the condenser water pump and fan horsepower increases (assumes variable frequency drive motors), and the answer will depend on equipment loading (i.e., part load performance). As another example, the cost of operating a chiller to generate chilled water for turbine inlet cooling may be far outweighed by the value of increased combustion turbine generator output. Algorithms exist to optimize individual plant systems, such as the chilled water and condenser water systems, and to operate equipment along its natural curve of best efficiency points for a given load and operating conditions. Using power consumption meters, empirical method can also be used to plot power consumption versus various applicable operating parameters in order to determine operating conditions that minimize power consumption.

As discussed, the heat rate is a measurement of the power generation effectiveness and the lower the heat rate the more efficient is the prime mover at generating power (less fuel is required per unit power output). Minimizing the heat rate will help minimize fuel consumption for a given output. The heat rate is affected by the prime mover design, by the plant layout and installation (which are fixed in a constructed plant), and by operating conditions such as the outside air temperature, which can be mitigated through turbine inlet cooling.

Many institutions are making public, written pledges to reduce their facilities carbon footprint, and, as described, the use of CHP inherently minimizes a facility's carbon footprint. By minimizing losses, maximizing CHP efficiencies, minimizing parasitic power consumption, and the heat rate, fuel consumption for a given load is minimized and CHP environmental benefits will be enhanced.

Operator Training

Plant operators are very important in the success of any facility operations, as it is the plant operators who are on the front line and can observe and report plant operating conditions and make key suggestions for improvements, and it is the plant operators, for example, who implement and make work (or not) management/consultant recommended plant

energy conservation measures. Having knowledgeable, trained plant operators is essential for CHP plants, and, therefore, ongoing operator training is essential to sustainability. No matter how much an individual knows, more can be learned. Additionally, technology continues its rapid advance and continuous training/education is required to maintain proficiency. Also, rules and regulations change, and facilities operators need to be familiar with any items affecting their facility. Changing priorities may also require education, for example, as energy efficiency/pollution reduction become more important to a facility's overall mission.

Maintenance

Thorough, ongoing maintenance is essential to sustainable CHP plant operations. Every plant must have a preventive maintenance (PM) system, and planned maintenance shutdowns must be carefully coordinated. If the CHP plant was designed with backup equipment, unexpected failures can be successfully handled without disruptions to operations. Unplanned disruptions to CHP plant operations can be minimized with good operations and maintenance, by operating the plant in a stable and safe manner, and by maintaining equipment in good working order. There are number of software programs and systems available to manage maintenance operations, with different degrees of sophistication. However, the basic concept is to track each and every piece of equipment, heat exchanger, valve, control device, and every device needing maintenance along with the corresponding required maintenance items for each item (e.g., change oil, change fluids, lubricate fittings, change belts, and check clearances) as well as the schedule for those maintenance items (e.g., daily, monthly, quarterly, and annually) to develop an overall plant maintenance schedule.

Reserve Funds

All equipment, no matter how well maintained, eventually wear out and must be replaced. Facilities can and should plan for equipment replacements by establishing a reserve fund. A CHP plant reserve fund is another equipment matrix that lists each and every piece of equipment along with the equipment's respective:

- Date put into service
- Remaining life expectancy in years
- Current cost to replace
- Future cost to replace
- Current reserve amount
- Calculated current reserve requirement
- Current reserve amount versus calculated current reserve amount (surplus or deficit)
- Annual amount needed to be added to the reserve fund

The future cost to replace is estimated by escalating the current cost to replace by the number of years of equipment life remaining. The calculated current reserve requirement is also determined from the future cost to replace and the remaining equipment

life versus the total expected equipment life taking into consideration the time value of money. For example, neglecting inflation and savings interest, if a piece of equipment cost \$100,000 and the life expectancy is 20 years, the facility should add \$5000 to the reserve fund every year and if 6 years of life remained, then the reserve fund should hold \$70,000 for that piece of equipment in this simplified example. Of course, in reality, purchase escalation costs as well as return on reserve fund investments must be taken into account.

Insurance Requirements

The responsibility for developing a risk management strategy and arranging and placing the insurance clearly lies with the designated CHP plant owner-operator following completion of construction, receipt of permit to operate from all authorities having jurisdiction, and completion of 24/7 shift operator hands-on training and commissioning. The coverages are essentially the same as for the construction phase except for the need to address the CHP plant equipment breakdown and business interruption exposures.

The financial interests also have a keen interest in the insurance program from day one, and will want an assurance that the CHP plant owner-operator can service the debt, that is has other insurance against the financial consequences of interruption of CHP plant operations.

With respect to the CHP plant time operational exposures, for example, delay in CHP plant start-up and interruption to power sales, the willingness of the insurer to grant the latter additional insurance coverage will depend upon the ability of the CHP plant owner-operator and their insurance broker to adequately explain the nature of anticipated exposure to the insurance underwriters.

When the insurance broker is asked to quote coverage for business interruption, he understands that during a period of business interruption its insurance must cover the cost of the insured CHP plant owner-operator's continuing expenses, business earnings including profit that the CHP plant owner-operator would have been responsible for and due had no loss from business interruption occurred. It is important for the CHP plant owner-operator to understand that the period of recovery applies only for the time required to repair or replace damaged CHP equipment and/or related physical plant structure, property, etc. assuming reasonable speed is undertaken to fix the problem so that normal CHP plant operations are not unreasonably delayed.

Expect insurers of technical risk situations, generally associated with on-site CHP plant operations, to expect detailed engineering data and documents detailing maintenance histories and procedures, fire protection system capabilities, and operating logs to properly underwrite the CHP plant owner-operator's account.

The basics of business interruption are slightly more complex when insuring CHP plant owner-operators. Disagreement and/or confusion over agreement on lost CHP plant income, and expenses or how to budget for CHP plant operating interruption exposure offer the leading cause of insurer disinterest in dealing with CHP plant exposure.

Since most owner-operator CHP plant purchase agreements provide for availability clauses and incentives, the actual period of loss can extend well beyond the repair period. Underwriters and claims adjusters, when not completely familiar with the terms of such customer contracts, may resist accepting the agreed upon incentive or penalty clauses

with CHP plant customers. Another area of potential confusion involves loss of capacity payments caused by a failure during a power purchaser availability test. When the subject policy contains a daily deductible for business interruption, a CHP plant owner-operator claim may be denied because the CHP plant had not yet met the specified waiting period. Accordingly, it is important that the CHP plant risk manager and insurers risk advisor/broker have access to those negotiating the power purchase contracts and have an opportunity to discuss the terms of a pending power purchase agreement so that the various loss scenarios be “gamed out” to verify that everyone understands the various triggers, clauses, and incentives contained in the contract. With that knowledge, your broker can offer suggestions on the best way to structure a program that provides the most efficient insurance coverage at reasonable cost.

Financing contracts and power purchase agreements typically span a number of years. Even though the above-mentioned markets have been long-term players, willingness to provide particular coverages, grant certain deductibles, or provide specified limits has changed over the years. Therefore, if a contract contains very explicit insurance requirements with respect to specific coverages, limits, or retentions, it is quite possible that over the course of the contract one will face a market cycle that blocks the availability of the required coverages.

As an additional complication, the financial strength of an insurer is a concern to everyone. Often lenders will require that a facility purchase insurance from only “A” rated companies. While this is an admirable goal, it may not be realistic, given the long term of the contract.

Attempt to secure as flexible insurance terms as possible. However, this does not mean ignore insurance until the last moment. Consider adding a provision such as “as available on reasonable terms and conditions” to allow you to adjust to market cycles. Some insurers are willing to consider multiple year programs. These can be beneficial as long as the cancellation clauses are understood on both sides.

Let People Know the Great Results of CHP

Finally, let people know the great results of having a sustainable on-site CHP system. Let people know that on-site CHP is a time-tested, proven technology that offers many important benefits to building and facility owners and operators, to local and regional utility systems, to a country’s economic competitiveness and security, and to human society as a whole. Let people know that sustainable on-site CHP’s important benefits include

- Lowered overall facility energy costs
- Increased total system efficiency
- Improved overall facility reliability
- Reduced electric demand on constrained utility grid and fully loaded generation equipment
- Reduced source energy use (i.e., total fuel consumption)
- Reduced total CO₂ emissions, which have been linked to global warming
- Ability to use biofuels, which are sustainable and essentially carbon neutral

Case Studies

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CHAPTER 19

Case Study 1: Princeton University District Energy System

Edward Borer

The Princeton University central plant and energy systems shown in the picture (Fig. 19-1) above are considered “best in class.” The systems exemplify the efficiency, reliability, and responsible financial and environmental stewardship that can be achieved by well-integrated energy systems. They are recognized as a model of excellence.

Princeton uses cogeneration, steam- and electric-powered cooling, thermal storage, district energy, and economic dispatch to deliver reliable energy at a minimum life-cycle cost while greatly reducing the university’s carbon footprint. While some existing university buildings date prior to the American Revolution, the facilities staff takes a proactive approach for testing and implementing the most modern methods and technologies. They have pioneered economic dispatch techniques, the use of biodiesel in boilers and gas turbines, the use of modern backpressure steam turbines, reduced biocide use, and optimized combustion turbine controls. The plant itself is frequently used as a teaching tool and is a key component of the university’s sustainability plan. Current projects in progress include exhaust heat recovery, venturi steam traps, heat recovery from returning chilled water, and real-time equipment dispatch based on economics and environmental impact. The university is a recognized leader in environmental stewardship winning many notable honors including the Governor’s Environmental Excellence Award and the Environmental Protection Agency (EPA) Energy Star CHP Award.

History

Princeton’s energy plant serves over 9 million square feet of residential, administrative, academic, athletic, and research space dating from the 1760s to today. Over a million



FIGURE 19-1 View from Princeton's energy plant roof. (*Courtesy of Christopher M. Lillja.*)

square feet of additional space to be served by district energy is planned for the next decade.

In 1754, the Fitz Randolph family donated 4-1/2 acres of property to allow construction of the first buildings of what is now Princeton University. With that gift was included "200 acres of woodland for fuel." This deed represented the first consideration of energy needs for the campus. Today the university can use over 26 million watts, 240,000 lb of steam per hour, and 13,000 tons of cooling to meet the electrical, comfort, and research needs of over 12,000 people.

The history of Princeton's energy systems reflects the history of the campus and the United States.

In 1876, the first boilers and district steam system were installed in Dickinson Hall to provide "heating steam for nearby public buildings." Four years later the boilers were relocated to "the New Dynamo Building" which included a steam-driven generator. Exhaust steam was used to provide heat for public buildings—the first cogeneration system on campus. Among other things this modernization allowed the use of safer electric lighting in the operating room of Professor Joseph Henry—who until that time had open-flame gas lamps in the same room where he was using ether for anesthetization!

In 1903, the University Power Company installed a new facility that included a 500-kVA, 2400-V, two-phase Curtiss steam turbine generator. The dormitories were still heated by coal. Soon after, 750-kW and 1250-kW generators were added. In 1923, a "university gothic" stone boiler house was built. It included three balanced-draft boilers with

steam-driven induced-draft (ID) and forced-draft (FD) fans to allow for short exhaust stacks that met campus architectural requirements.

In 1950, three new vibro-grate boilers replaced the originals and a 750-kVA, 26-kV substation was built on the far side of the campus.

The existing chilled water plant was built in 1960 and began with a 700- and 1100-ton chiller. The plant was entirely steam-driven until the need for off-peak cooling dictating the use of a small electric-driven pump. In 1965, the original 500-kVA Curtiss generator was replaced with a 3750-kVA three-phase generator. In 1964 and 1965, 2200- and 3400-ton chillers were added. In 1967, the boilers were converted from coal and oil to natural gas, rail lines that had been used for coal deliveries were removed and air pollution standards were imposed. The boilers were retubed to add efficiency and 10 to 15 percent capacity.

In 1970, the campus substation was expanded to 15,000 kVA and the first dormitory bedrooms were added to the district heating system. In 1978, a campus energy management system was installed in response to the energy crisis. In 1985, a 1500-ton electric chiller was added. In 1986, an additional 20-kVA substation was constructed. In 1988, a second 1500-ton electric chiller was installed.

By the late 1980s, the main boilers were in need of extensive (and expensive) repairs. Air emission laws would also require significant control upgrades. After many design studies, plans for a cogeneration system were developed that allowed more economical and less polluting simultaneous generation of heat and power.

The Modern Cogeneration Era

In 1996, the cogeneration plant replaced the boilers and added 15 MW of generating capability. Over the 1990s, all CFCs in the chilled water plant were replaced with HCFCs and chiller speeds were increased to recover their original capacities. In year 2000, by replacing an original 700-ton steam-driven chiller with a 2500-ton electric chiller, the plant cooling capacity was brought to 15,500 tons.

In 2001, Princeton added an economic dispatch model of the plant that was to provide expert guidance for the plant operators. Prior to this, plant equipment had been operated for reliability based on a general understanding of seasonal fuel and electricity prices. Over the next few years, a complete energy and economic dispatch system was developed to most cost-effectively meet the campus energy needs. On August 1, 2003, this system became far more valuable due to the increased electric price volatility caused by deregulation of New Jersey electric markets.

In 2005, the stone boiler house was renovated and now houses the offices of public safety and campus planning. 40,000 ton-h of chilled water thermal storage and two additional chillers were installed adding capacity, reliability, and economic responsiveness to the energy plant.

In 2006, the Elm Drive and Charlton Street Substations were upgraded and circuit breakers were added to provide two independent feeds to each side of the campus from the PSEG 26-kV system.

In 2007, Princeton pioneered the use of biodiesel. The energy plant was the first to obtain an Environmental Improvement Pilot Test permit to burn biodiesel in stationary boilers in New Jersey. The plant also was the first in the world to operate a General Electric LM-1600 gas turbine on biodiesel.

In 2008, another form of combined heat and power was added to the district energy system. Two Carrier "Microsteam" backpressure turbine-generators were installed in

Dillon Gym mechanical room. These produce approximately 500 kW while controlling the steam pressure between the 200-psig high-pressure distribution system and the 15-psig low-pressure distribution system on campus. This was the first installation where two Microsteam systems have been operated in parallel.

Central Energy Plant and Systems

Princeton’s central energy plant provides up to 15 MW of electricity, 300,000 pounds per hour (pph) of steam, and 25,000 tons of cooling to the campus. Major production equipment includes: a GE LM-1600 gas turbine, a Nebraska Boiler heat recovery steam generator, two dual fuel Indeck auxiliary boilers, five electric chillers, three steam-driven chillers, and a 40,000 ton-h thermal storage system. This varied mix allows Princeton to provide electricity and thermal energy in a reliable and efficient manner to the university campus. Through careful design and operation, the energy plant saves millions of dollars for the university each year and greatly reduces net emissions to the environment. Figure 19-2 is the Princeton energy plant energy flow diagram showing the energy inputs, plant equipment and processes, and plant utility outputs.

Electricity Production

The Princeton University energy plant is capable of providing 15 MW of electricity to the campus. This is accomplished with the use of a GE LM-1600 gas turbine generator (see Table 19-1). The nominal heat rate of the aeroderivative turbine is 9983 Btu/kWh (gas fired, 55°F inlet), approximately 34 percent efficient. With cogeneration, system efficiency improves to over 73 percent and is often over 80 percent efficient when firing the HRSG duct burner.

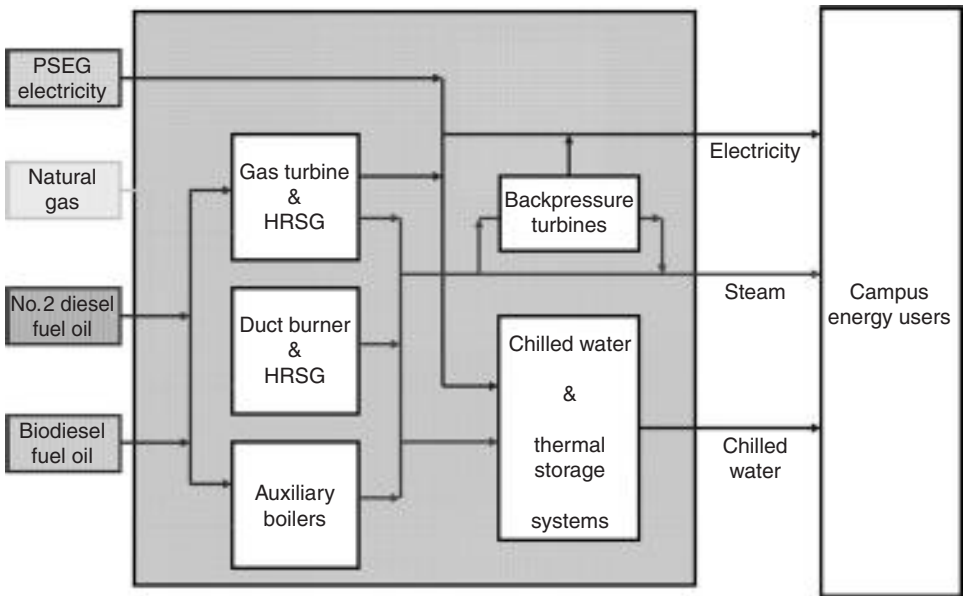


FIGURE 19-2 Princeton energy plant—energy flow diagram.

Tag	Capacity	Heat Rate (Simple Cycle)	Cogeneration Design Efficiency	Emissions
GTG-1	15 MW	9,983 Btu/kWh at 55°F inlet	> 80%	1.2 lb per MWh of NO _x

TABLE 19-1 Technical Data for GE LM-1600 Gas Turbine

The cogeneration system also includes the ability to duct fire to provide additional heating capacity. Typical efficiency with duct firing on natural gas is over 80 percent. The cogeneration system was installed in 1996.

Electricity Distribution

The electricity distribution system is set up for seamless transition between local production and utility service. The system allows for a combination of local production and utility service and the ability for the campus to fully isolate itself and perform as a power island when campus demand is within the generator's capability. These capabilities improve the overall system reliability and flexibility.

Two independent feeds from the local utility to each of two major substations provide extremely high reliability.

The system is set up with auto-transfer switches to provide the seamless performance. Service from the local utility is provided at 26 kV and is distributed to the campus at 4160 V. The gas turbine generator produces electricity at 4160 V to match campus distribution requirements. A supervisory control and data acquisition (SCADA) system monitors the entire electricity distribution system.

Steam Production

Table 19-2 lists operational data for the plant's steam production equipment and as shown steam is produced by the cogeneration process or from two auxiliary boilers. The cogeneration process produces steam via a heat recovery steam generator (HRSG), which utilizes the 950°F waste heat from the combustion turbine. The HRSG is capable of producing 50,000 pph of 225-psig, 450°F steam when unfired. With the burners operating, the capacity of the HRSG increases to 180,000 pph. Each of two auxiliary boilers can produce 150,000 pph of steam. The HRSG duct burner is configured to

Tag	Description	Capacity (Unfired)	Capacity (Fired)	Steam	Emissions
HRSG -1	Heat recovery steam generator	50,000 pph	182,000 pph	225 psig, 450°F	Included with GTG-1
BLR-1	Dual fuel boiler	N/A	150,000 pph	225 psig, 450°F	33 ppm of NO _x
BLR-2	Dual fuel boiler	N/A	150,000 pph	225 psig, 450°F	33 ppm of NO _x

TABLE 19-2 Technical Data for CHP Components

burn natural gas, while the boilers and gas turbine are capable of firing natural gas or diesel fuel.

The boilers are approximately 83 percent efficient when firing using natural gas and 87 percent when firing with No. 2 diesel fuel. The duct firing process is approximately 82 percent efficient. The boilers were installed in 1996.

Steam Distribution and Condensate Collection

Steam at 225 psig is delivered to the steam turbines in the chilled water plant for use in chilled water production. Additional steam is delivered to the campus to serve space heating and research needs. Main steam pressure is 220 psig. This is reduced to 45 to 90 psig in the distribution system, and dropped below 15 psig at each building entrance.

The campus steam distribution network consists of insulated carbon steel piping in small steam and condensate tunnels and larger multiutility walk-through tunnels. Some condensate piping is direct buried. Condensate is pumped back to the plant with typical recovery of 75 to 85 percent. This high rate of recovery results in a minimum of water, chemical, and thermal waste.

An ongoing condensate recovery improvement program involving plant operations, campus maintenance, and facilities engineering staff identifies problems and targets areas of opportunity to improve the campus condensate recovery rate. In recent years, this program has lead to the repair or replacement of dozens of condensate pumps, added thermal insulation to thousands of feet of pipe, tested and planned replacement and upgraded hundreds of steam traps.

Chilled Water Production

As shown in Table 19-3, chilled water is produced in the existing chilled water plant with eight centrifugal chillers. Three of the chillers are driven by steam turbines. Up to 9410 tons of cooling can be delivered from steam-driven equipment. Five electric-drive chillers can be supplied with power from the cogeneration system or the local utility. These three chillers are capable of producing 10,225 tons. The thermal storage system has an 8-hour discharge rate of 5000 tons, for a total cooling capacity of 24,635 tons.

The chillers were installed over time, with the oldest installed in 1965 and the newest installed in 2005. Chillers 2100 and CH-2200 can be used both for thermal storage and to meet the immediate needs of the campus.

Tag	Drive	Capacity (Tons)	Efficiency	Refrigerant
CH-1	Steam turbine	4,500	8.86 lb/ton	R-22
CH-2	Electric-drive	2,500	0.5 kW/ton	R-123
CH-3	Steam turbine	1,850	11.4 lb/ton	R-134a
CH-4	Steam turbine	3,060	11.9 lb/ton	R-134a
CH-5	Electric-drive	1,375	0.63 kW/ton	R-134a
CH-6	Electric-drive	1,350	0.72 kW/ton	R-134a
CH-2100	Electric-drive	2,700	0.58 kW/ton	R-123
CH-2200	Electric-drive	2,300	0.71 kW/ton	R-123

TABLE 19-3 Technical Data for Chilled Water Production Components

A 2.6-million-gallon chilled water thermal storage system was installed in 2005. It has a design capacity of 40,000 ton-h with a 24° differential temperature. The system was designed for “fast discharge.” Four 2500-ton plate-and-frame heat exchangers were included to provide chemical and hydraulic separation from the campus and to allow the system to deliver up to 10,000 tons of cooling. This makes the system extremely responsive to changes in economic dispatch and campus emergencies. To maximize thermal storage capacity and improve the campus temperature differential, the chilled water (CHW) storage temperature on the plant side of the heat exchanger is 31°F, resulting in supply water as cold as 34°F available to the campus. Low storage temperatures are achieved without the risk of freezing by using a density depressant additive. Low distribution supply temperatures improve dehumidification capability, reduce pumping energy requirements, and increase the distribution system capacity by approximately 20 percent.

Chilled Water Distribution

Princeton’s chilled water distribution piping network consists of a combination of tunnels and direct buried piping. Chilled water is normally distributed to the campus at 41°F with a typical return temperature, at higher loads, of 54°F. By specifying high delta-T coils (typically 20° temperature rise) and pressure-independent control valves for all new construction and renovation projects, the chilled water temperature differential and system capacity have steadily improved each year.

Water Systems Quality Management

By carefully monitoring and managing the water quality in all energy systems, Princeton maintains high water-side efficiencies and long equipment life in chillers, boilers, cooling towers, and air-handling units. This also minimizes health and safety risks, and prevents corrosion and biological fouling in piping and control equipment. Princeton runs a three-tiered water quality management program: Plant personnel sample and test water systems at least once each shift. A water treatment company representative repeats these tests and performs additional analysis and makes recommendations on a weekly basis. Every 3 months, an independent water treatment consultant samples and performs tests. Then, a water systems meeting is held involving plant operators, campus maintenance personnel, water treatment company representatives, and the independent water chemist. All results are compared and discrepancies, concerns, and opportunities for improvement are discussed. The following systems are included in this program: chilled water, boiler feed water, returning condensate, city water, well water, cooling tower water, and thermal storage water.

Plant Controls

The energy plant has separate control rooms for the cogeneration plant and the chilled water and thermal storage facilities. The controls are fully integrated in one system so operators in both areas have complete plant indication and can respond to alarms and troubleshooting in a consistent and straightforward way.

The plant control system is based on the Allen Bradley PLC hardware and Intellution iFix 32 human-machine interface. The control system provides all supervisory, control,

reporting, and data acquisition functions for plant operations. Control rooms include multiple operator workstations, and an economic dispatch workstation. The cogeneration control room also includes continuous emissions monitoring and an electrical distribution/synchronizing panel. All plant control systems are fully backed up by a UPS (uninterrupted power supply) and diesel generator.

Instrumentation

Extensive instrumentation is installed throughout the energy plant. Plant personnel continuously monitor key process parameters to optimize economic performance. The same database is used by the plant economic dispatch system. Historical data is then collected and used to document fuel and water use and energy delivery, and to project future energy needs. This database has become an invaluable resource for campus master planning, engineering decisions, and individual system designs.

Real-Time Economic Dispatch

In August 2003, commercial electric purchases in New Jersey were deregulated. Prior to that, Princeton purchased power at fixed day, night, weekend, and seasonal rates. Since deregulation, Princeton has purchased power at a continuously varying wholesale market rate. At night, prices are often as low as \$20 per megawatthour—far below Princeton's marginal cost to generate power, and on a hot summer day the price for electric power has risen to \$1000 per megawatthour. Both liquid and gas fuel prices have risen and have become more volatile since 2003. This provides strong incentive for Princeton to be a very market-sensitive energy customer.

With the original tariff, the cogeneration system was run to follow campus load. Any campus load not met by cogeneration was imported from the grid. To take advantage of today's energy market, Princeton plant operators need to regularly make changes in power generation, fuel selection, thermal storage/discharge, demand-side management, and the use of steam or electric-driven chilling.

In response to the wholesale market, a real-time economic dispatch system was developed by Princeton and Ictec that continuously *predicts* campus energy demands and market prices and then recommends the most cost-effective combination of equipments to meet those requirements. The model inputs include real-time data for weather, NYMEX gas and oil prices, campus energy demands, equipment efficiencies, and availability. By using this system the plant operator's focus shifts from simply meeting demand to delivering energy in the most cost-effective manner.

Princeton has found that in a highly volatile market, the cogeneration system operates *fewer* hours, but is actually worth *more* since there are more opportunities to shut down cogeneration and purchase power from the grid less expensively, and more opportunities to run at high load and avoid the highest-cost purchased power. The key to Princeton's economic dispatch is predicting those opportunities in advance and being prepared to take advantage of them.

While this system could be fully automated, Princeton chooses to have plant operators use it as expert guidance—since there are times when safety, reliability, or critical campus events are more important than short-term economics. The operators' union contract includes opportunities for annual bonus pay based on high compliance with the economic dispatch signals. This has been a very successful program for both the university and operations personnel.

Service Availability and Reliability

Electric Service Availability and Reliability to Campus Was 100 Percent over a 1 Year Period

Princeton has installed two independent power feeds from the local utility to each of the two major substations serving the north and south halves of the campus. Although the utility had a 101-minute service interruption to the south substation, the gas turbine automatically picked up the campus load—so there was no customer impact.

Steam service reliability to campus was 99.9 percent as indicated by steam header pressure above 100 psig. There were no unplanned interruptions of more than 3 hours. Steam service availability was 99.7 percent.

Energy Production Efficiency

In fiscal 2007, Princeton Energy Plant purchased 1.497×10^{12} Btu of natural gas and diesel fuel and delivered to the campus: 27,944,000 ton-h of cooling, 584,121,000 lb of steam, and 35,412,000 kWh of electricity, representing *a net thermal efficiency of over 73 percent*. When the 87,360,000 kWh of purchased power are included, total energy delivery efficiency rises to 77.8 percent! This translates into important energy and environmental savings. But equipment dispatch is based primarily on minimizing the cost of energy delivered to the campus, not strictly on maximizing thermal efficiency.

Princeton selects all equipment for high efficiency if it is expected to run with high capacity factors during peak cost hours. The university specifies premium efficiency motors and typically uses variable-frequency drives on pumps and fans with variable loads above 5 hp. Chillers CH-1 and CH-2 (described earlier) are typically base loaded during peak hours. These are both highly efficient machines. *The cogeneration system regularly operates with measured efficiencies above 80 percent.*

Environmental Benefits, Compliance, and Sustainability

Through the use of combined heat and power, Princeton Energy Plant avoided nearly 12,000 metric tons of carbon dioxide production this past year compared to equivalent energy delivery from the local electric utility and heating boilers.

The plant is designed and operated to meet all emissions requirements and includes: turbine water injection for NO_x control, a carbon monoxide catalyst, low- NO_x burners, and flue gas recirculation in the auxiliary boilers. The primary fuel is natural gas with ultralow sulfur diesel as a backup fuel. Continuous emissions monitors measure CO , O_2 , and NO_x and document compliance with emissions regulations.

Princeton has shown leadership in developing one of the most aggressive sustainability plans of all colleges and universities. By year 2020, Princeton has committed to reduce all CO_2 emissions to year 1990 levels—by making changes on campus as shown in Fig. 19-3—and without purchasing “offsets.” The plan includes greenhouse gas reduction, resource conservation, primary research, education, and civic engagement. The central energy plant and district energy systems will be key to the success of this major campus initiative.

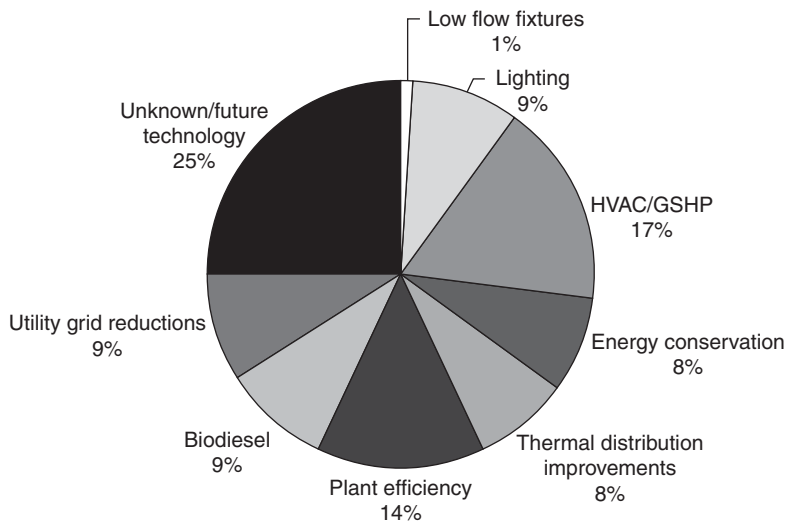


FIGURE 19-3 Princeton campus CO₂ reduction goals chart.

Pioneering Work and Industry Leadership

- Since the 1870s, when Princeton installed the first district heating and cogeneration systems on campus, the university has been a pioneer in energy. That tradition continues today.
- Princeton energy plant was the first in New Jersey to obtain an Environmental Improvement Test Permit to burn biodiesel in its stationary boilers. The plant was the first in the world to operate an LM-1600 gas turbine on biodiesel. Both tests were highly successful and the university has obtained New Jersey Department of Environmental Protection (NJDEP) permission to add biodiesel as a third fuel option in its operating permit.
- Princeton collaborated with General Electric to develop the first gas turbine control based on maintaining a fixed steam header pressure rather than a fixed power output—to optimize the economic dispatch during spring and fall when thermal loads are low.
- Princeton collaborated with Nalco Chemical to pioneer the use of adenosine triphosphate (ATP) testing to identify the source of biological fouling in condensate systems.
- Princeton is now using chlorine dioxide as a more effective and less environmentally damaging biocide for chilled water systems.
- Princeton is testing and measuring the effectiveness of two different manufacturer’s venturi-style steam traps.
- Princeton has recently installed an advanced exhaust heat recovery system for the cogeneration plant.

- Princeton worked with Carrier Corporation to install and properly control the first side-by-side application of two 270-kW Microsteam backpressure turbine generators.
- Princeton collaborated with Ictec to develop the most advanced economic dispatch system found in any district energy plant. This is a “living” system that is continually being improved to meet the changing needs of the campus, the plant operators, and campus administrators. Recently, Princeton and Ictec have added “real-time carbon emission measurement” to the system.

Employee Safety and Training

- With a total plant staff of 29, the energy plant has averaged fewer than 15 lost workdays per year for the past 8 years. This represents a rate of 0.21 percent.
- Plant personnel are continuously trained on safe operation and maintenance practices and are actively involved in continuous improvement of plant safety.
- Princeton conducts an extensive safety and training program that includes involvement from operating union personnel and the campus Environmental Health and Safety (EHS) office. A root-cause analysis and written report is performed following any reportable accident.
- All key stakeholders on campus including EHS, engineering, plant operators, electric shops, and building maintenance personnel are currently involved in developing an NFPA-70 Arc Flash safety program.
- The plant safety committee meets on a quarterly schedule to discuss any issues that are raised, ranging from union shop rules or changes to policies, procedures, or code requirements. Along with the safety committee, Princeton provides annual training along with frequent toolbox talks that the EHS office recommends. In order to efficiently communicate to plant personnel on all shifts, a password-accessible Web site has been created where operating memos and all safety procedures are available from any Web-accessible computer. Plant safety training programs include
 - Emergency action and fire prevention plan
 - Right to know survey with MSDS documentation
 - Required personal protective equipment
 - Respirator protection program for air purifying respirators
 - First aid
 - Cardiopulmonary resuscitation (CPR)
 - Fuel oil spill response
 - Response to fire in gas turbine and gas compressor
 - Campus utility interruption guidelines
 - Blood-borne pathogen exposure control
 - Automated external defibrillator (AED) unit operation and emergency response

Customer Relations and Service to the Community

- Princeton University Energy Plant is recognized as an industry leader and its personnel actively promote best practices in energy.
- University courses in engineering, economics, and environmental policy regularly include lectures from energy plant personnel and tours of the facility. The plant and campus energy systems have been the subject of numerous student studies and academic papers.
- The plant and its staff were recently featured in an hour-long NJN public television documentary: "Green Builders" that "profiles a cast of green building pioneers who have taken the leap into making their part of the 'built environment' a more energy-efficient and environmentally friendly place." It can be watched online at <http://www.njn.net/television/specials/greenbuilders/showvod.html>.
- Energy plant management and personnel are actively involved in professional organizations including the International District Energy Association (IDEA), the American Society of Heating Refrigeration and Air-Conditioning Engineers (ASHRAE), the Association of Energy Engineers (AEE), the LM-1600 Owners Group, the American Society of Mechanical Engineers (ASME), and the New Jersey Higher Education Partnership for Sustainability. They regularly write articles and present talks for these groups in an effort to promote best practices related to efficiency, the environment, and sustainability.
- Plant personnel have supported IDEA by traveling to Washington, DC, to meet with congressional and U.S. Department of Energy staff to discuss the merits of district energy.
- Tours of the facility are often included in "best practices benchmarking" activities by schools and companies such as: Columbia, Rutgers, Bristol Meyers Squibb, Princeton Plasma Physics Laboratory, University Medical & Dental School of New Jersey, New Jersey Board of Public Utilities, the New Jersey Pharmaceutical and Food Energy User Group, and Capitol Health.
- The plant Web site, originally created to provide thorough, consistent information for operations personnel, has been expanded to include a public face with contact information, history, and details about the plant as well as live campus energy and weather data: http://www.princeton.edu/facilities/engineering_services/energy/. Visitors see a new image every time they reload the page.

Recent Honors and Awards

Princeton energy plant and facilities engineering have been honored with the following:

- United States EPA CHP Partnership: Letter of Recognition, 2009
- U.S. EPA: CHP Energy Star Award, 2007
- New Jersey Smart Start Program: Over \$400,000 in awards for implementation of energy efficiency projects, various years

- New Jersey Department of Environmental Protection, and New Jersey Corporation for Advanced Technology: Governor's Environmental Excellence Award, 2007
- New Jersey Higher Education Partnership for Sustainability: Green Design and Practice Award, 2002
- Steel Tank Institute: Steel Tank of the Year, 2005
- American Council of Engineering Companies: National Recognition Award, 2007
- Boston Society of Architects chapter of American Institute of Architects: Award for Design, 2006

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CHAPTER 20

Case Study 2: Fort Bragg CHP

Steve Gabel

James Peedin

Fort Bragg, a U.S. Army post located in North Carolina is the home of the army's Airborne and Special Operations Forces. One of the largest army installations in the world, Ft. Bragg is a key operations center for the army's rapid deployment forces. In 2004, a Honeywell-led project team completed the installation of a large combined heat and power (CHP) system at the post's 82nd Central Heating Plant as shown in Fig. 20-1.

This CHP project was financed primarily through a public-private partnership via an Energy Savings Performance Contract (ESPC). The cooling portion of the system was supported by a research and development contract from the U.S. Department of Energy (DOE) through Oak Ridge National Laboratory (ORNL), with technical assistance from the Army Corps of Engineers and the Federal Energy Management Program (FEMP).

Technical Overview

The 82nd Central Heating Plant is the largest of 14 central plants on the post. The plant provides district heating service to approximately 50 barrack buildings and other facilities with 125-psig steam and 210°F hot water (converted from steam) for space heating. The plant also serves a year-around heating load for domestic hot water and food service needs. The plant provides district cooling service to a smaller number of buildings with 45°F chilled water for space cooling.

The major equipment in the CHP system consists of a 5-MW combustion turbine generator, a 1000-ton, exhaust-driven absorption chiller, a heat recovery steam generator (HRSG) and an auxiliary gas-fired duct burner. The turbine generator is fired with either natural gas or fuel oil (to offer the army plant operators a fuel option based on cost).

The plant also includes an auxiliary gas-/oil-fired steam boiler and an auxiliary electric centrifugal chiller for either backup or additional capacity when required. The CHP system has an electrical power generating capacity of 5250 kW, and an unfired

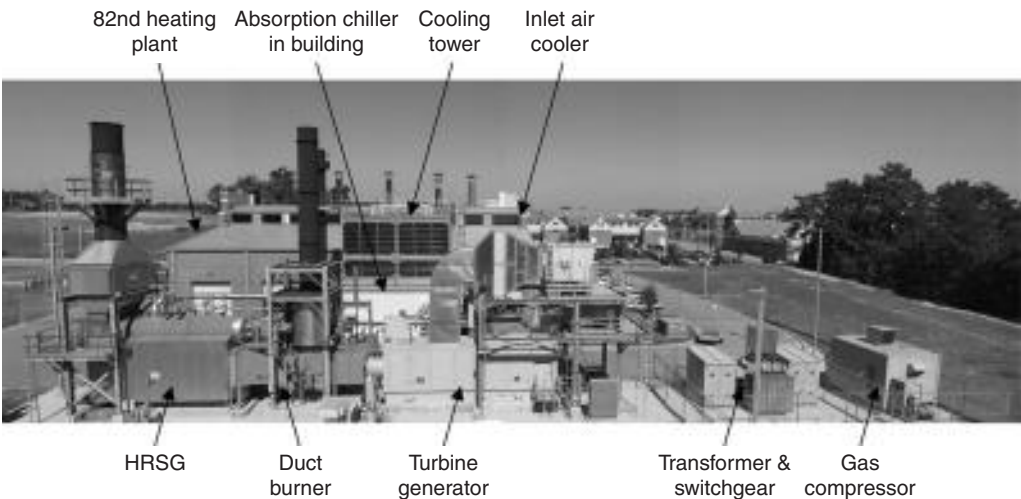


FIGURE 20-1 CHP system installation.

heating capacity of 28,700 lb/h of steam at nominal ambient conditions (60°F). During periods of high heating load, the auxiliary duct burner is employed to increase the steam output of the HRSG to 80,000 lb/h. The plant operating staff can also use an inlet-air cooling coil to increase the electrical power generating capacity of the turbine generator during periods of high ambient temperatures. A diagram of the CHP system is shown in Fig. 20-2.

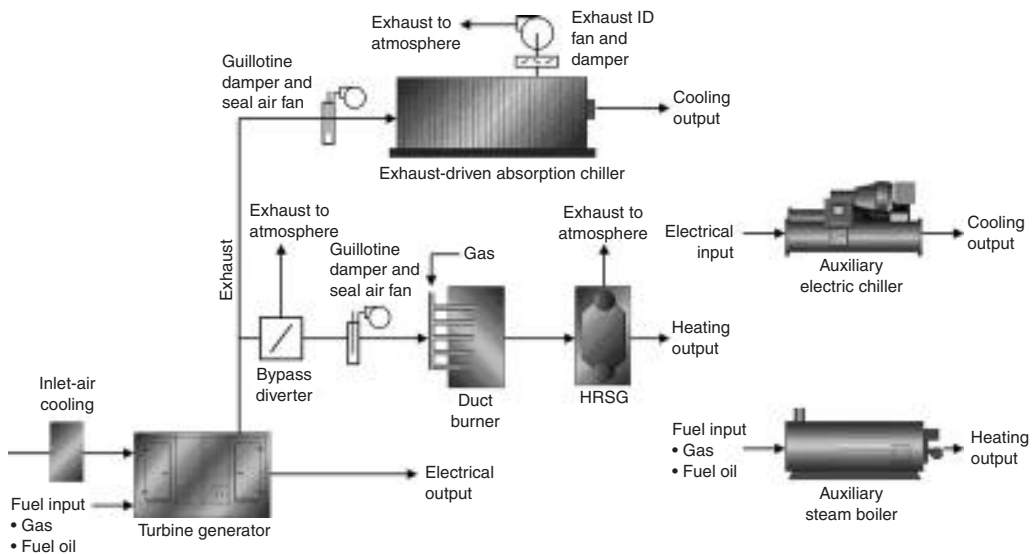


FIGURE 20-2 CHP system installation.

As originally configured, the peak cooling load for the connected buildings served could be satisfied entirely by the 1000-ton absorption chiller. Following start-up of the CHP system, expansion activity at Ft. Bragg was expected to result in increased demand for heating and cooling from this plant as new buildings were brought online. The project team and the Ft. Bragg Directorate of Public Works worked together to plan future plant modifications to meet the increased heating and cooling demand.

CHP Interconnection

The combustion turbine generator produces electrical power at 13.8 kV, which is then isolated by a 13.8/12.47-kV transformer. The generator is connected directly into one of four distribution 230/12.47 kV substations with a 50-MVA capacity. The substation has reverse power relay protection to ensure that there is no backfeeding to the high voltage grid. The typical minimum load for the substation is 15 MVA. There also are dedicated feeders to other critical loads.

In addition to the CHP generator, a number of emergency generators elsewhere on the post can be paralleled with critical loads in the event of an extended grid outage. However, that switching is not automated as part of this project. The first response to a grid outage is to revert to emergency generators and an uninterruptible power supply (UPS) for a seamless transfer. The system can be reconfigured in the future should conditions warrant.

Plant Operations

The CHP equipment is a key tool which the Ft. Bragg operating staff uses to manage energy demand and energy cost on a daily basis. During winter months, the system's operating strategies are driven by fuel prices; as a result, the system is typically operated in a thermal load-following mode. By adjusting the output of the turbine, plant operators are able to produce all of the steam and hot water requirements while also having the added benefit of producing up to 5 MW of electrical power for use on the post. This thermal load-following strategy minimizes the amount of unrecovered thermal energy in the turbine exhaust. During periods of high heating demand, the duct burner is employed to ensure sufficient heat input to the HRSG. Plant operators use fuel oil as an alternate fuel source for the turbine generator based on fuel prices, the availability of natural gas—which is purchased on an interruptible basis—and the emissions constraints of the plant's operating air permit.

During summer months, the CHP system's operating strategies are driven by the price of electricity. The system's operation is continuously adjusted to best respond to the two-part rate under which the post purchases electricity. A portion of the energy charge is determined by a real-time price for energy consumption above a specified contract base load. To minimize operating costs during periods of high electric prices, the turbine generator is operated at full load together with inlet-air cooling to maximize electrical power output. Recovered exhaust heat is used to drive the absorption chiller and is also delivered to the HRSG to satisfy the year-round thermal load on the post. During the design phase of this project, the CHP equipment sizing was carefully matched to the expected thermal loads in order to minimize unrecovered turbine exhaust energy. During periods of lower electric prices, the inlet-air cooling can be deactivated and the system can be operated in a thermal load-following mode.

The CHP system is operated in a number of different control strategies to minimize operating costs. Optimization software that is resident in the plant's supervisory

control system determines the best operating strategy on an hourly basis. This optimizer considers the electric load, heating and cooling loads, grid electricity and fuel prices, equipment characteristics, and weather data to determine how to best meet these loads using the CHP equipment, electric grid power, and the auxiliary heating and cooling equipment. The optimization software guides the plant operations staff by recommending set points for the turbine generator and other major equipment. The economic performance (i.e., cost savings) provided by the CHP optimizer software is a function of the energy prices, energy loads, and equipment characteristics of the site. Simulations of this software have shown an estimated annual energy cost savings of approximately 5 percent over the typical, nonintegrated operating strategy. In practice, the actual annual performance will vary as energy prices and energy loads fluctuate. Ft. Bragg central plant operations and overall post energy management functions are managed from a central Energy Information Center.

Overall, the post has a maximum peak demand of approximately 110 MW, with most of the electrical power being purchased from a local electric utility. The CHP system's electric power generating capacity of up to 5 MW can be combined with approximately 8 MW of diesel generator capacity on the post to manage energy costs and provide a measure of energy security. These on-site generating assets provide an energy security benefit in that they can be used to serve critical loads on the post in the event of a disruption on the electrical grid.

Measured Performance

This project included a period of detailed performance monitoring of the CHP system, covering the period of June 2004 through August 2005. A system block diagram showing the performance analysis boundaries is shown in Fig. 20-3. In the following sections, the CHP system is referred to as an integrated energy system (IES).

Energy Delivery

A high-level summary of energy delivery for the monitoring period is shown in Fig. 20-4 and Table 20-1. Runtime and generation results (as well as all other measurements) during the 2004 summer season were affected by periods of downtime due to extended commissioning activity and delays in acquiring an emissions operating permit. Also note that the duct burner's start-up in March resulted in a significant increase in steam production. Reduced demand lowered steam production in the following month.

Operational Monitoring

A high-level summary of operational results for the monitoring period is shown in Fig. 20-5 and Table 20-2. The definition of system efficiency is taken as (useful energy output)/(total energy input from fuel). The IES system energy efficiency is based on the lower heating value (LHV) of the fuel input. Energy efficiency calculations were made in accordance with "Distributed Generation Combined Heat and Power Long-Term Monitoring Protocols" Interim Version, October 29, 2004,

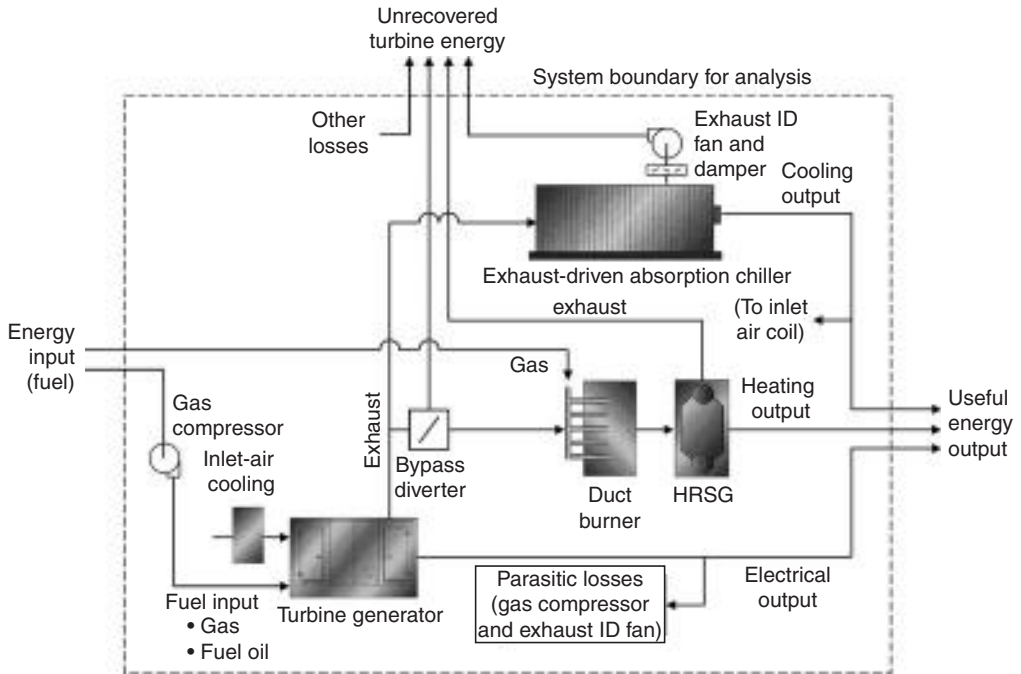


FIGURE 20-3 CHP system boundaries for performance analysis.

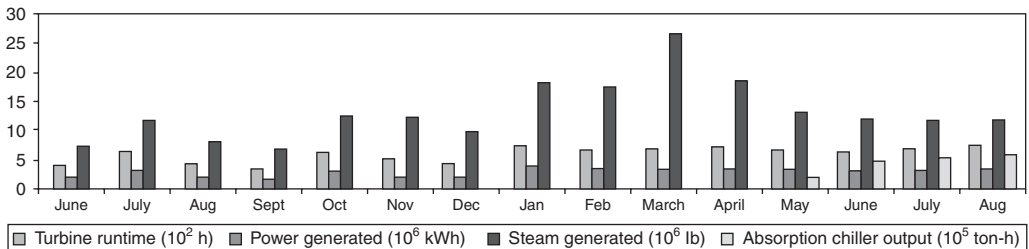


FIGURE 20-4 Energy delivery results, June 2004 through August 2005.

prepared by the Association of State Energy Research and Technology Transfer Institutions (ASERTTI). Seasonal energy efficiency is noted monthly in this section and quarterly in the subsequent.

Overall Energy Utilization

A high-level summary of energy utilization is shown in Table 20-3. Input and output energy fluctuations reflect changes in utility prices and seasonal climate changes.

	Turbine Runtime (h)	Power Generated (kWh)	Steam Generated (lb)	Absorption Chiller Output (ton-h)
June	384	1,904,408	7,392,141	—
July	651	3,189,374	11,923,695	—
August	432	2,053,839	8,130,529	—
September	338	1,664,393	7,001,374	—
October	635	3,169,605	12,520,358	—
November	513	2,654,199	12,374,470	—
December	445	2,262,950	9,808,411	—
January	730	3,876,281	18,302,123	—
February	668	3,515,882	17,495,770	—
March	688	3,553,763	26,515,075	—
April	702	3,543,983	18,422,213	—
May	672	3,456,023	13,226,844	188,622
June	651	3,074,551	11,983,409	476,606
July	695	3,098,944	11,716,781	538,104
August	735	3,327,250	11,906,622	578,439

TABLE 20-1 Energy Delivery Results, June 2004 through August 2005

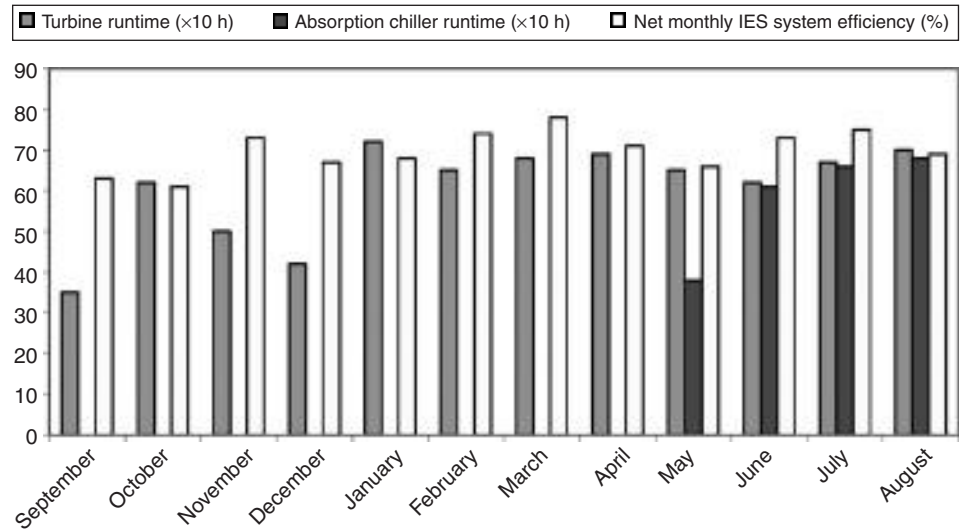


FIGURE 20-5 Operational results, September 2004 through August 2005.

		Turbine Runtime (h)	Absorption Chiller Runtime (h)	Net Monthly IES System Efficiency (%)
2004	September	338	—	65.4
	October	635	—	63.0
	November	513	—	72.0
	December	445	—	67.2
2005	January	730	—	72.0
	February	668	—	74.1
	March	688	—	80.2
	April	702	—	74.2
	May	672	404	67.9
	June	651	648	76.0
	July	695	693	77.2
	August	735	705	73.7

TABLE 20-2 Operational Results, September 2004 through August 2005

		Fall 2004	Winter 2005	Summer 2005
Input energy (MMBtu)	Turbine fuel oil	3,029	120	—
	Turbine gas	111,934	169,347	155,605
	Duct burner gas	—	9,168	—
	Total input	114,963	178,635	155,605
Output energy (MMBtu)	Unrecovered turbine energy	37,511	43,131	43,702
	HRSg steam	44,126	86,064	52,057
	Net turbine electric	32,647	48,434	43,073
	Net absorption chiller cooling	—	—	19,521
	Total output	114,284	177,629	158,353
Net IES efficiency		66.8%	75.3%	73.6%

TABLE 20-3 Energy Utilization Result

Key Results

The performance of the CHP system was carefully monitored during the initial months of operation. A list of the key performance-related outcomes is shown in Table 20-4. The project team identified a number of lessons learned that can help other engineers in the industry. A list of key design-related outcomes is shown in Table 20-5.

Key Outcomes	Remarks
1. Parasitic energy consumed by the induced draft (ID) exhaust fan was not a significant issue, in terms of overall system energy efficiency (This variable speed ID fan is used to control exhaust heat input to the absorption chiller)	Measured field data over a complete cooling season showed that the ID fan was not a major contributor to parasitic energy required to operate the system
2. Seasonal variations in energy efficiency are to be expected, due to varying thermal loads and equipment operating characteristics	The measured performance was very good, and met the expectations defined at the beginning of the project. Monthly energy efficiencies of up to 80% (based on LHV) were measured
3. System-level performance can be measured, and design intent verified with proper field instrumentation	Steady-state performance can be measured quite adequately using standard control system quality instrumentation. More in-depth investigations might require more elaborate instrumentation and data collection equipment. Careful attention to sensor calibration is also a key ingredient to success
4. Equipment-level performance can also be measured, and design intent verified with proper field instrumentation	The measured field data verified that each item of major equipment in the CHP system was able to meet or exceed its design performance specifications
5. Cleaning of turbine blades should be done according to the turbine manufacturers' recommendations	Careful monitoring of blade condition will keep the turbine operating at or near the desired performance

TABLE 20-4 Key Outcomes of the Performance Monitoring Work

Key Outcomes	Remarks
1. Commissioning is a very important part of a CHP installation project	As with any building- or plant-level energy system
2. Guillotine dampers can be made to perform in an exhaust-driven chiller application (Note: A guillotine damper is needed to protect the absorption chiller from hot exhaust gases, when the chiller is not in operation)	There is no need for specially designed guillotine dampers, although there may be a need to carefully adjust the damper slide mechanism during plant commissioning
3. Additional instrumentation (beyond that required for control purposes) is a valuable part of a CHP project	Additional sensors provide more information to plant operators and energy managers, about equipment and system operating performance

TABLE 20-5 Key Design-Related Outcomes of the Project

Key Outcomes	Remarks
1. Site operating staff should maintain a proper inventory of critical spare parts or plan carefully to be sure they are procured before they are needed. Examples are air and fuel filters, and other key consumables	Poor planning can result in lost operating time of the CHP system from unplanned outages caused by a lack of the necessary spare parts
2. High fuel prices (vs. electric prices), during periods of low thermal loads can make it uneconomical to operate the CHP system	This illustrates the benefit of having control optimization capability
3. If not carefully planned, emissions permitting can delay initial plant start-up and commissioning	Begin the permitting process early, and follow up to make certain that all requirements are met prior to completion of the site construction work
4. Interconnection with local electric utility (protective relaying, etc.) is a key element of a CHP project	Coordination with the electric utility on commissioning the interconnection is one of the key elements of plant start-up

TABLE 20-6 Key Operations-Related Outcomes of the Project

The operating history of the CHP system was carefully monitored during the initial months of operation. A list of key outcomes relating to CHP plant operations is shown in Table 20-6.

Future Directions

Over the first 4 years of operation, plant operators at Ft. Bragg found that the system provided good performance, but required more maintenance than they had expected. In addition, some of the CHP equipment is unlike other equipment in the army's central heating and cooling plants, thereby requiring the use of outside contractors for some specialized maintenance work. During the first 4 years of operation of the CHP system, there was a large increase in the connected cooling load due to new building construction on the post. This increased cooling load will require modifications to the 82nd Central Heating Plant. These modifications are planned to include revisions to the chilled water distribution system to enable better use of the existing electric-driven chiller and the addition of new chiller capacity. Experience has shown that during periods of high cooling demand, the connected buildings on the post require a chilled water supply delivered at 42°F, which has been difficult to achieve with absorption technology. As a result, the army is exploring options to deactivate the exhaust-driven double effect absorption chiller as part of the planned plant modifications.

This new direction is not a reflection of the suitability of exhaust-driven absorption technology for CHP systems. Exhaust-driven absorption chillers or chiller-heaters remain a viable design option that should be strongly considered in planning any CHP system application.

Conclusion

This CHP system is designed to recover turbine energy using an exhaust-driven double effect absorption chiller installed in parallel with an HRSG. This arrangement is a bit more complex than the typical CHP system that would utilize an HRSG and a steam-driven absorption chiller. While system designers expect a limited performance benefit due to the use of an exhaust-driven unit, there is one significant advantage to this type of equipment. In applications that do not require steam production, an exhaust-driven unit can be delivered in the form of a “chiller-heater,” which can produce chilled water as well as low-temperature hot water (170°F) from the same unit. By eliminating the need for an HRSG, the use of an exhaust-driven chiller-heater can greatly simplify the design—and reduce the installed cost—of a CHP system. The chiller-heater approach is expected to be the logical path toward the goal of wider application of exhaust-driven absorption technology. The study of this CHP project highlights the possibilities of packaged CHP solutions (Chap. 5), the importance of managing operational efficiency (Chap. 17), and the results of detailed operation and maintenance criteria (Chap. 16).

CHAPTER 21

Case Study 3: Optimal Sizing Using Computer Simulations— New School

Itzhak Maor

T. Agami Reddy

This case study is meant to illustrate the sizing of the prime mover and the absorption chiller using a detailed simulation program. A school campus located close to New York City has been selected to illustrate the application of its principles and methodology as outlined in Chap. 8 by means of a representative CHP “schematic phase” simulation and LLC evaluation (see Chap. 9).

With it, the project engineer or developer can evaluate the most likely outcome of one or more CHP alternatives before having to commit additional resources needed for subsequent detailed design and construction phases, after gaining reasonable assurance that the CHP plant configuration selected should be a cost-effective investment.

The sizing of the prime mover and the absorption chiller is based on the CHP optimizer program by Hudson¹ for which hourly heating, cooling, and nonchiller electric loads are required along with certain performance and cost data.

A DOE 2.1 E building energy simulation model was developed for a large 229,700-ft²-high school facility designed to accommodate around 1500 students. New York corresponds to area 5A in the geographical locations established by ANSI/ASHRAE/IESNA Standard 90.1-2007, normative appendix B (based on Briggs et al.).² As shown in Fig. 21-1, the facility is a campus comprises the following areas:

1. Two three-story classroom wings
2. One two-story special classroom wing which includes library and special areas such as educational labs and computer classrooms

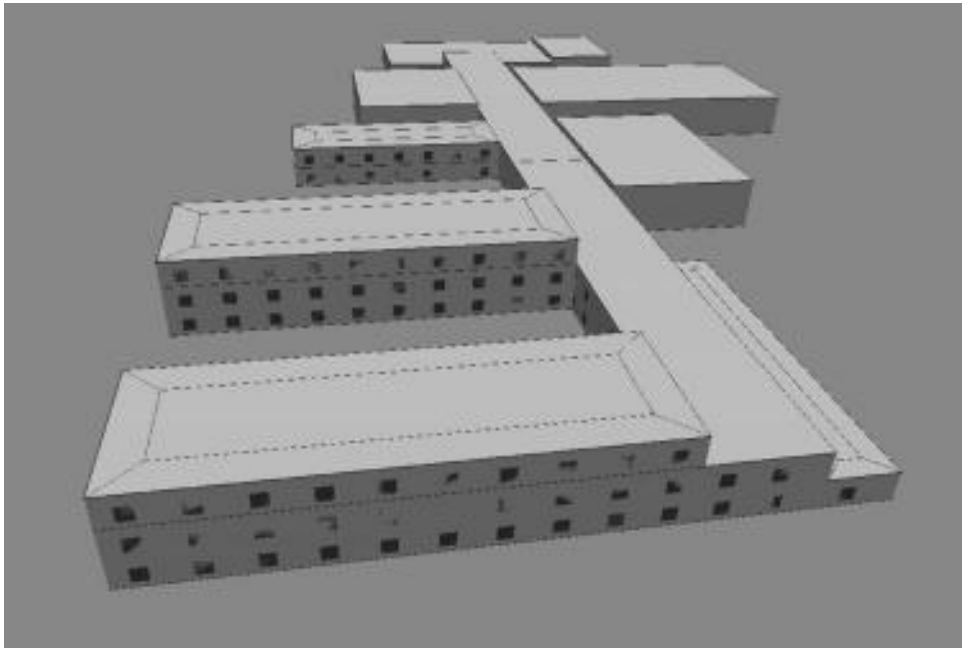


FIGURE 21-1 Rendering of school campus.

- 3. Two gymnasium wings to accommodate three gymnasiums
- 4. Auditorium wing
- 5. Cafeteria wing
- 6. Central utility plant to accommodate chillers, boilers, pumps, etc.
- 7. One-story administration annex
- 8. Two-story common (link) section

Building envelope properties, systems efficiencies, operating schedules (lighting, occupancy, etc.), and the like are based on the design preliminary design documents and criteria. A variety of secondary air systems are proposed for the design, these systems include four-pipe fan coils (FPFC) for classrooms, variable air volume (VAV) with reheat for the common areas, and admin and single zone (SZ) for auditorium, gymnasiums, and cafeteria. A summary of the building description is assembled in Tables 21-1 and 21-2.

Since the cost of electricity can vary every hour, the cost of the electricity consumption and demand need to be specified for each hour of the year. Further, there is a different electrical tariff for CHP applications, which will result in different electrical prices for the proposed CHP system. The electrical energy costs are time-of-use (TOU) price signals as shown in Tables 21-3 and 21-4 for non-CHP and in Tables 21-5 and 21-6 for the CHP application. The gas price is \$7.75/MMBtu based on lower heating value (LHV).

	Data
General	
Location	NYC area, NY
Floor area (ft ²)	229,700
Above grade floors	Varies (3, 2, and 1 depending on duty)
Below grade floors	0
% Conditioned and lit	100
Buildings/Wings	
Classrooms	Three wings, three and two story (98,000 ft ²)
Auditorium	One wing (12,600 ft ²)
Gymnasiums	Two wings (31,900 ft ²)
Cafeteria	One wing (14,400 ft ²)
Office/admin	One annex (5,400 ft ²)
Central utility room	One annex (5,400 ft ²)
Common (wings link)	62,000 ft ²
Floor-to-floor height (ft)	13 (typical), in gymnasiums, auditorium, etc. is higher
Floor-to-ceiling height (ft)	9 (typical)
Envelope	
Roof	Massive, R-25
Walls	CMU grouted, 2 in, EIFS, 30% abs, U = 0.1 (Btu/h-ft ² -°F)
Foundation	Slab, U = 0.03 (Btu/h-ft ² -°F)
Windows	Double glazing low E, U = 0.416 (Btu/h-ft ² -°F), SHGC = 0.43
Windows-wall ratio (%)	16
Exterior and interior shades	None

TABLE 21-1 Description of Large School Campus

	Data
Schedules	
Operation schedule	Per school schedules
Secondary Systems	
Classrooms	Four-pipe fan coils
Auditorium	Single zone
Gymnasiums	Single zone
Cafeteria	Single zone
Office/admin	Variable air volume with hot water reheats
Central utility room	Single zone
Common (wings link)	Variable air volume with hot water reheats

TABLE 21-2 Description of Large School Schedules and Systems

Electric Rates (Non-CHP Energy)		Pattern 1		Pattern 2	
Month	Pattern #	Energy Hour	Rate (\$/kWh)	Energy Hour	Rate (\$/kWh)
1	2	1	0.1029	1	0.0903
2	2	2	0.1029	2	0.0903
3	2	3	0.1029	3	0.0903
4	2	4	0.1029	4	0.0903
5	2	5	0.1029	5	0.0903
6	1	6	0.1029	6	0.0903
7	1	7	0.1029	7	0.0903
8	1	8	0.1029	8	0.0903
9	1	9	0.1029	9	0.0903
10	2	10	0.1029	10	0.0903
11	2	11	0.1029	11	0.0903
12	2	12	0.1029	12	0.0903
		13	0.1029	13	0.0903
		14	0.1029	14	0.0903
		15	0.1029	15	0.0903
		16	0.1029	16	0.0903
		17	0.1029	17	0.0903
		18	0.1029	18	0.0903
		19	0.1029	19	0.0903
		20	0.1029	20	0.0903
		21	0.1029	21	0.0903
		22	0.1029	22	0.0903
		23	0.1029	23	0.0903
		24	0.1029	24	0.0903

TABLE 21-3 Non-CHP Electrical Energy Cost Information

First, the hour-by-hour building energy simulation program is created with the information shown in Tables 21-1 and 21-2. The building loads data provided by this program along with the electrical and gas price signal data are exported to the ORNL CHP Capacity Optimizer program. Specifically, the information that is required for the optimal selection of the prime mover and the absorption chiller involves:

1. Hourly electrical demand values excluding the chiller electrical load (it should be noted that the building energy model has to include at least one chiller for

Non-CHP Demand		Pattern 1	\$/kW-mo
Month	Pattern #	Demand Hour	Peak
1	1	1	15.406
2	1	2	15.406
3	1	3	15.406
4	1	4	15.406
5	1	5	15.406
6	1	6	15.406
7	1	7	15.406
8	1	8	15.406
9	1	9	15.406
10	1	10	15.406
11	1	11	15.406
12	1	12	15.406
		13	15.406
		14	15.406
		15	15.406
		16	15.406
		17	15.406
		18	15.406
		19	15.406
		20	15.406
		21	15.406
		22	15.406
		23	15.406
		24	15.406

TABLE 21-4 Non-CHP Electrical Demand Cost Information

automatic sizing). The hourly electrical demand that will be used in the ORNL CHP Capacity Optimizer program should not include this hourly chiller electrical demand. This is shown in Table 21-7 under “Net Electrical (kW).”

- Hourly thermal load values (space heating, domestic hot water, and other thermal loads) are shown in Table 21-7 under “Total Thermal (Btu).”
- Hourly cooling load values are shown in Table 21-7 under “Cooling (Btu).”

Electric Rates (CHP Energy)		Pattern 1		Pattern 2	
		Energy Hour	Rate (\$/kWh)	Energy Hour	Rate (\$/kWh)
Month	Pattern #				
1	2	1	0.06757	1	0.05551
2	2	2	0.06757	2	0.05551
3	2	3	0.06757	3	0.05551
4	2	4	0.06757	4	0.05551
5	2	5	0.06757	5	0.05551
6	1	6	0.06757	6	0.05551
7	1	7	0.06757	7	0.05551
8	1	8	0.06757	8	0.05551
9	1	9	0.12571	9	0.08793
10	2	10	0.12571	10	0.08793
11	2	11	0.12571	11	0.08793
12	2	12	0.12571	12	0.08793
		13	0.12451	13	0.08793
		14	0.12451	14	0.08793
		15	0.12451	15	0.08793
		16	0.12451	16	0.08793
		17	0.12451	17	0.08793
		18	0.12451	18	0.08793
		19	0.12571	19	0.08793
		20	0.12571	20	0.08793
		21	0.12571	21	0.08793
		22	0.12571	22	0.08793
		23	0.06757	23	0.05551
		24	0.06757	24	0.05551

TABLE 21-5 CHP Electrical Energy Cost Information

A typical hourly report obtained from the hour-by-hour energy simulation program is shown in Table 21-7. The data shown is only for one day while all 365 days of the year (or 8760 hours) will be required to run the optimizer program.

Prior to running the initial iteration, preliminary information must be inputted to the optimizer. Table 21-8 shows all required general data. Data concerning demand and rates (to include electrical, fuel, and escalation) are also required. Furthermore, CHP

CHP		Pattern 1			Pattern 2	
Demand Month	Pattern #	Demand Hour	\$/kW-mo Peak*	Off-Peak	Demand Hour	\$/kW-mo Peak
1	2	1			1	
2	2	2			2	
3	2	3			3	
4	2	4			4	
5	2	5			5	
6	1	6			6	
7	1	7			7	
8	1	8			8	
9	1	9			9	8.901
10	2	10			10	8.901
11	2	11			11	8.901
12	2	12			12	8.901
		13	20.758		13	8.901
		14	20.758		14	8.901
		15	20.758		15	8.901
		16	20.758		16	8.901
		17	20.758		17	8.901
		18	20.758		18	8.901
		19			19	8.901
		20			20	8.901
		21			21	8.901
		22			22	8.901
		23			23	
		24			24	

*Empty cells are hours with no electrical demand charges.

TABLE 21-6 CHP Electrical Demand Cost

Month	Day	Hour	Total Power (kW)	Chiller Input (kW)	Net Electrical (kW)	Cooling (Btu)	Heat Load (Btu)	DHW Load (Btu)	Total Thermal (Btu)
6	24	1	151	0	151	0	0	0	0
6	24	2	151	0	151	0	0	0	0
6	24	3	151	0	151	0	0	0	0
6	24	4	151	0	151	0	0	0	0
6	24	5	151	0	151	0	0	0	0
6	24	6	364	88	275	633,392	0	1,339	1,339
6	24	7	387	97	290	704,616	107,190	2,678	109,868
6	24	8	429	128	302	929,132	100,962	4,017	104,979
6	24	9	497	172	325	1,297,076	98,005	5,356	103,361
6	24	10	490	166	325	1,199,914	92,565	5,356	97,921
6	24	11	499	174	325	1,305,016	92,887	6,695	99,582
6	24	12	542	204	338	1,819,809	96,918	5,356	102,274
6	24	13	550	207	343	1,869,372	98,185	5,356	103,541
6	24	14	556	213	343	1,964,145	98,334	4,017	102,351
6	24	15	554	211	343	1,927,063	98,807	2,678	101,485
6	24	16	544	206	338	1,850,608	99,296	4,017	103,313
6	24	17	525	199	327	1,730,005	102,681	1,339	104,020
6	24	18	195	0	195	0	0	0	0
6	24	19	198	0	198	0	0	0	0
6	24	20	190	0	190	0	0	0	0
6	24	21	190	0	190	0	0	0	0
6	24	22	190	0	190	0	0	0	0
6	24	23	170	0	170	0	0	0	0
6	24	24	151	0	151	0	0	0	0

TABLE 21-7 Sample of Building Load Data Required by the Optimization Program [Data for one day (24th June)]

operation parameters (i.e., hourly costs versus user defined) and component exclusions may also be specified. Certain variables such as prime mover (DG) “DG electric efficiency (full output)” and “DG power-heat ratio” may be adjusted after the first iteration (which will provide initial optimal sizing) by using actual electrical efficiency and power-heat ratio from manufacturer’s design data.

Variable	Value
On-site boiler efficiency	80.0%
Conventional chiller COP	4.30
DG electric efficiency (full output)	37.2%
DG unit minimum output	30%
Absorption chiller COP	0.70
Absorption chiller minimum output	25%
Abs chiller system electricity requirement (kW/RT)	0.02
CHP O&M cost (\$/kWh)	0.011
DG power-heat ratio	0.83
Number of DG units	1
Type of prime mover	Reciprocating Engine
Discount rate	8.0%
Effective income tax rate	0.0%
DG capital cost (\$/net kW installed)	1500
AC capital cost (\$/RT installed)	850
Planning horizon (years)	16

TABLE 21-8 General Data Required for the ORNL CHP Capacity Optimizer—Input

Once all input data is inserted, the program may accurately determine the optimum capacity. Figure 21-2 depicts the results of the optimal sizing and additional calculated data such as the total annual electricity, heating, cooling, and annual costs, NPV, etc. In addition to the tabulated data the user can see graphically the results of the optimization where the x axis represents the optimal prime mover size (kW) and the size of the absorption chiller (tons) in the y axis.

As shown in Fig. 21-2, the optimization program indicates that for the prime mover and the absorption chiller the optimum capacities are 500.1 kW and 109.2 tons, respectively. The exact size of the prime mover and the absorption chiller will be based on the owner requirements for redundancy and the actual sizes of the equipment available commercially.

A similar approach can be used for existing buildings; in this case, the hourly loads as shown in Table 21-7 will be obtained from the calibrated simulation. Any combination of new and existing buildings can be accommodated in the CHP optimizer. This simulation illustrates the fundamental design concepts found in Chap. 8 and life-cycle-cost analysis covered in Chap. 9.

Results

Demands	Electricity	Heating	Cooling
Annual	3,106,896 kWh	8,264 MMBtu	375,147 RT-hr
Maximum	1024 kW	9.7 MMBtu/hr	522 RT
Minimum	150 kW	0.00 MMBtu/hr	0 RT
Installed DG capacity:		500.1 kW (net)	Manual DG Capacity Input
Installed AC capacity:		109.2 RT	
Installed capital cost:		\$842,827	Manual AC Capacity Input
Hours of DG operation:		4,610 hours/year	
DG generated electricity:		1,915,134 kWh/year	
DG supplied heating:		3,965 MMBtu/year	
AC supplied cooling:		154,707 RT-hr/year	
Annual costs (before tax)	With CHP	No CHP	
CHP system	\$163,281	\$0	
Utility elec	\$115,124	\$451,542	
Non-CHP fuel	\$22,397	\$61,102	
Total	\$300,802	\$512,645	
Annual operating savings (after tax):		\$211,843	
NPV savings:		\$1,032,170	
Optimum DG capacity:		500.1 kW	
Optimum AC capacity:		109.2 RT	
NPV savings:		\$1,032,170	

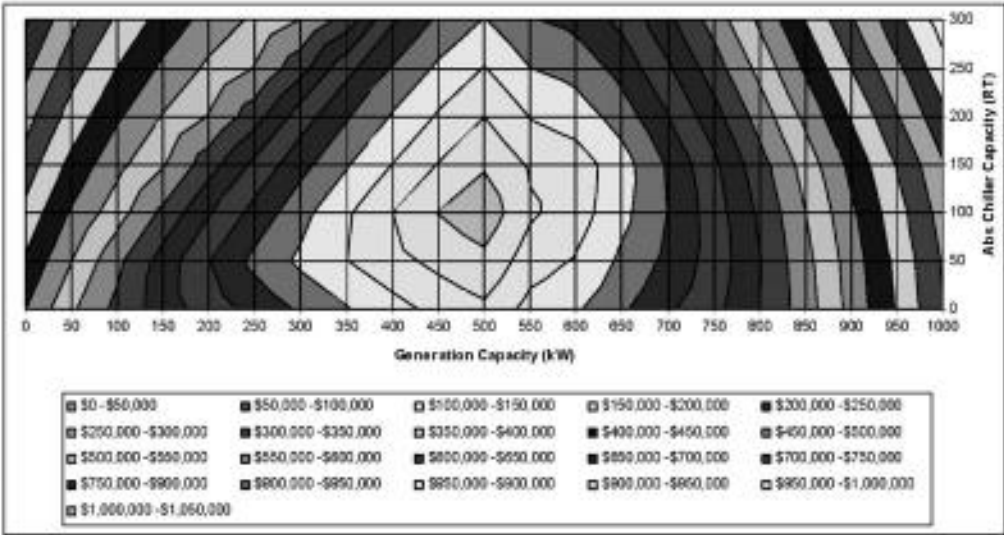


FIGURE 21-2 Screen capture of the ORNL CHP Capacity Optimizer output.

References

1. Hudson, C. R., 2005. ORNL CHP Capacity Optimizer: User's Manual, Oak Ridge National Laboratory Report ORNL/TM-2005/267.
2. Briggs, R. S., Lucas, R. G., and Taylor, T. 2003. Climate Classification for Building Energy Codes and Standards: Part 2—Zone Definitions, Map, and Comparisons, ASHRAE Transactions, 109(1), 122–130.

CHAPTER 22

Case Study 4: University Campus CHP Analysis

Dragos Paraschiv

University campuses typically include a large number of buildings with, quite often, very diversified usage including

- Academic buildings
- Offices
- Laboratories
- Athletics
- Dormitories and residences
- Commercial buildings

Campus facilities are usually operated by the facilities management or physical resources group, which is also in charge of maintaining and repairing equipment in these facilities. Another major task of the physical resources group is the utility management for the university. In many North American universities, the campus utilities are distributed to the on-site buildings and facilities from a central utilities plant. University utility distribution systems often include various combinations of the following utility systems:

- Electrical power
- Natural gas
- Fuel oil
- Steam
- Hot water
- Chilled water

- Domestic cold water
- Domestic hot water
- Compressed air

Over time, typical university campuses expand and many facilities are in need of renovation and/or retrofit. In addition, many institutions have embraced sustainability as the foundation of their facility operations, and adopted sustainable development policies.

Given the mix of required utilities, which almost always includes electricity, heating, and cooling energy, the combined generation of heat and power becomes a very attractive option for universities that are faced with requirements to meet increased campus loads or retrofit/replace older equipment.

This case study analyzed the operation of a diversified central utilities plant and offers a methodology to help facilitate the decision-making process for the plant operators faced with open energy market conditions.

Central Utilities Plant Description

The university campus considered for this analysis includes buildings with a total area of approximately 7.5 million square feet. These facilities are served by a central utilities plant (CUP) and a distribution system with

- Steam—generated by
 - Two cogeneration units
 - Four steam boilers
- Chilled water—produced by
 - Six electric chillers
 - One absorption chiller
- Electricity—generated by
 - Two cogeneration units
- Compressed air—generated by
 - Three air compressors
- Domestic water supplied by the municipality

For the purpose of this central plant optimization analysis, compressed air and domestic water were not included. Table 22-1 presents the CUP utility inputs and outputs considered in this case study.

Utility In	Utility Out to Campus
Natural gas	Steam (cogen or boilers) Raw utility used: natural gas
Electricity	Chilled water (electric chillers or absorber) Raw utility used: electricity and/or steam
Electricity	Electricity (grid transfer or cogen) Raw utility used: electricity and/or gas

TABLE 22-1 Conversions or Transfers within CUP

Cogeneration Equipment

The cogeneration plant consists of

- Two combustion turbine generator sets
- Two heat recovery steam generators (HRSGs), with integrated natural gas-fired duct burners

Each of the turbine generators has a capacity of approximately 5 MW of electricity at 13.8 kV and can produce 25,000 lb/h of steam at 275 psig in the unfired HRSG. When the duct burners within the HRSG operate, the total steam production of each HRSG increases from 25,000 lb/h to 65,000 lb/h of saturated 275-psig steam, for a combined output of 130,000 lb/h. Firing the duct burners to increase the steam generation capacity is possible with the combustion turbine exhaust gases that are rich in oxygen and at high temperature. The additional 40,000 lb/h of steam are produced at 94.5 percent efficiency, which is considerably higher than the efficiency of a steam boiler. Table 22-2 provides a summary of the CUP equipment design performance data.

The gas-fired steam boiler efficiency is used in any analysis to determine the equivalent cost of steam required by the campus, when the cogeneration units are inoperative.

When steam generated by the cogeneration plant is used to satisfy heating loads on campus, the cogeneration plant operates at its maximum efficiency. This steam is produced using waste heat from the combustion turbine and it substitutes steam otherwise generated by gas-fired boilers. However, when this steam cannot be used for heating purposes and is used, for example, in the absorption chiller, the overall plant efficiency is affected, as the absorber competes with the electric chillers in producing chilled water.

Absorption Chiller

Steam generated in the CUP can be used by a single-stage (or effect) absorption chiller to generate chilled water that is distributed to the campus buildings. Table 22-3 provides the absorption chiller design performance values.

The electric chiller efficiency is considered in any analysis in order to allow the comparison of the plant operation for the same campus load. When the absorption chiller is not used, an equivalent amount of cooling is generated by the electric chillers.

Campus Steam Load

Figure 22-1 depicts the steam delivered to campus over the course of a year as well as the amount of steam that is used by the single-effect absorption chiller.

Average steam boiler efficiency	80.0%
Cogeneration unit gas input	1,710 m ³ of gas/h
Cogeneration unit electrical output	4,700 kW
Cogeneration unit steam output (no duct burner)	25,000 lb/h of steam
Duct burner gas input	1,254 m ³ of gas/h
Cogeneration unit steam output (with duct burner)	65,000 lb/h of steam
Avg. cogeneration duct burner efficiency	94.5%
Cogeneration unit design efficiency	69.9%

TABLE 22-2 Cogeneration Equipment Performance Data

Absorber steam input	25,000 lb/h of steam
Absorber output	1,400 tons refrigeration
Absorber efficiency	18 lb of steam/ton-h
Electric chiller efficiency	0.7 kW/ton

TABLE 22-3 Absorption Chiller Performance Data

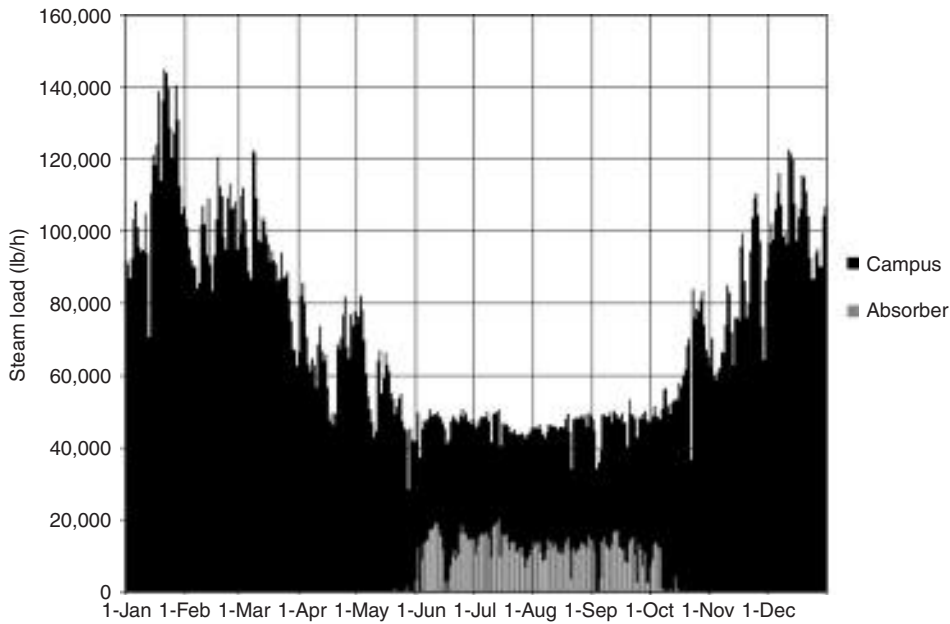


FIGURE 22-1 Annual steam consumption on campus.

Methodology for Cogeneration Plant Optimization

The technical basis of how the equipment operates to generate steam, chilled water, and electricity for the campus is generally well understood, and therefore, will not be discussed in great detail. The focus is on the way this “kit of parts” is being used and how to most effectively generate these utilities.

This study addresses the optimal modes of operation for the existing cogeneration plant under varying steam load conditions. For the equipment that is currently installed, several modes of operation are possible. The analysis here helps illustrate how the optimal mode of operation at any time depends on the magnitude of the difference between the campus steam demand and the combined steam generation capacity of the two cogeneration units, or in this case named “excess cogeneration steam.”

The proposed methodology calculates a break-even value for the excess cogeneration steam capacity and shows how the preferred mode of operation differs above and below this point. As can be expected, the break-even point varies as gas and electricity prices vary.

Operating Modes for Cogeneration Plant

The cogeneration plant contributes to the campus electrical and steam loads, and offers a versatile, reliable, and independent source of power that produces electricity at higher energy efficiency than fossil fuel utility power plants, provided that there is a use for the steam being produced.

However, energy efficiency and economic efficiency do not always correlate. The cost-efficiency of a cogeneration plant is inextricably linked to its ability to use 100 percent of both of the cogenerated outputs, electricity, and steam. Furthermore, the cost of natural gas must be such that in comparison to grid purchased kilowatthour and producing steam using conventional means, it allows for a positive cash flow in sufficient quantity to pay for capital cost repayment or return on investment (ROI) and maintenance and other operating costs.

Currently, during the late spring, summer, and early fall, the demand for steam by the campus buildings is less than the steam output of the two cogeneration units, 50,000 lb/h. At these times, plant operators use the excess steam into the single-effect absorption chiller. This chiller uses up to a maximum of 25,000 lb/h to generate up to 1400 tons of cooling in the form of chilled water. Using the absorber eliminates the need to generate these 1400 tons of cooling using an electrical chiller and reduces the CUP electric demand and load accordingly.

This interdependency between the equipment in the CUP can be summarized as follows:

- *Electricity.* The cogeneration units operate to match the electrical load of the campus, which translates into continuous full-load operation.
- *Steam.* As a result of the cogeneration, approximately 50,000 lb/h of steam is generated. When the campus steam load is higher than the output from the unfired HRSGs, duct burners, or supplementary boilers are used to generate the balance of required steam. When the campus steam load is below 50,000 lb/h uses for the steam must be found to minimize dumping.
- *Chilled water.* When the campus steam load is lower than 50,000 lb/h the steam plant pressure control is achieved by modulating the absorption chiller to maintain steam pressure, thus utilizing the absorption chiller as a steam dump. If the absorber cannot use the excessive steam, then the steam is dumped in a steam condenser that uses cooling tower water to condense the excess steam for thermal balance. It should be noted that using the dump condenser, the most onerous operating option, occurs only in case of equipment malfunctioning and is not a regular procedure.

When the campus steam load is over 50,000 lb/h, the plant can take full advantage of cogeneration and it is understood that the supplementary boilers would operate only when the cogeneration unit HRSGs and turbine exhaust duct burners, both operational, cannot meet the load.

This case study investigates the operation of the cogeneration plant at various campus loads lower than 50,000 lb/h, in order to develop an optimized operational strategy for the cogeneration units. To summarize, the following scenarios are presented:

- Two cogeneration units plus an absorption chiller
- One cogeneration unit plus duct burner

Electricity consumption	\$0.10 per kWh
Natural gas	\$0.35 per m ³
Steam	\$14.33 per klb
Chilled water	\$9.18 per MMBtu or \$0.11/ton-h

TABLE 22-4 Baseline Utility Rates

Utility Rates Used for Analysis

The rates in Table 22-4 are used in the analysis to determine the break-even point between the proposed scenarios. The electricity and natural gas rates shown are for utilities imported by the campus, and the steam and chilled water rates shown are for utilities distributed by the CUP to the campus facilities.

Equipment Modules for Economic Analysis

In order to compare the economics of different equipment combinations, the cost and revenue are determined for each equipment type. These values correspond to a period of 1 hour, assuming constant campus loads.

As shown in Table 22-5, when the duct burner is not fired, at the baseline gas price of \$0.35/m³, one cogeneration unit will consume 1710 m³ of gas worth \$598.50 in 1 hour. The cogeneration output for 1 hour will be 4700 kW of electricity plus 25,000 lb of steam. The delivered electricity rate is \$0.10/kWh, and the steam output is valued at \$14.33/klb. In the break-even analysis to follow, the gas cost appears as an expense, and the electricity and steam values both appear as revenues.

Using the electricity and gas utility rates noted in this case study, the cost of generating steam by one cogeneration unit can be calculated as follows:

$$(1710\text{ m}^3 \times \$0.35/\text{m}^3 - 4700\text{ kWh} \times \$0.10/\text{kWh})/25\text{ klb} = \$5.14/\text{klb of steam}$$

Note, this is the utility cost only, without the fixed costs or other operation and maintenance cost.

Should there be no concurrent demand for the steam generated from cogeneration waste heat, the steam is assigned a value of zero, and the cogeneration plant would run as a simple combustion turbine generator. The cost of generating electricity this way, without fixed costs or other operation and maintenance costs, would be \$0.127/kWh (\$598.50/4700 kWh). This cost is considerably higher than the locally available electricity market price, and they underline the need for a beneficial use for the steam from cogeneration in order to achieve a CHP plant competitive advantage.

Cogeneration Unit, without Duct Burners	
Gas input	1,710 m ³
Electrical output	4,700 kW
Steam output	25,000 lb

TABLE 22-5 Cogeneration Unit Parameters

Cogeneration Units, with Duct Burners	
Duct burner gas input	1,254 m ³ /h
Additional steam output with duct burner	40,000 lb/h
Specific consumption	31.35 m ³ /klb

TABLE 22-6 HRSG Duct Burner Parameters

Table 22-6 provides the CUP cogeneration units duct burner performance information. When a cogeneration unit is at full output, additional steam can be generated by combusting additional natural gas into the hot turbine exhaust before it enters the HRSG boiler. The efficiency of a duct burner is generally higher as compared to a comparable conventional boiler. At full load, additional hourly energy expense is $1254 \text{ m}^3 \times \$0.35/\text{m}^3 = \$439$ and the additional output is 40,000 lb of steam. At bare utility cost, the steam is produced at \$10.97/klb, and delivered to campus buildings at \$14.33/klb.

Absorption Chiller

The operating parameters for this equipment are presented in Table 22-3. Excess steam from the cogeneration units is used by the single-effect absorption chiller to provide chilled water for campus cooling. As noted, excess steam is produced whenever the campus steam consumption is less than the cogeneration plant output; and the cogeneration units must run at 100 percent output to meet the campus electrical load.

The output of the single-effect absorption chiller was valued, for purposes of this study, based on the equivalent amount of electricity an electric-powered centrifugal chiller would have consumed to provide the same amount of cooling as the single-effect absorption chiller.

Thus, the equivalent output of the absorption chiller for 1 hour is the steam input multiplied by the ratio of the efficiencies of the two chillers:

$$\text{Revenue} = 0.70 \text{ kWh/ton-h} \times \$0.10/\text{kWh} / 18 \text{ lb/ton-h} \times 1000 \text{ lb/klb} = \$3.88/\text{klb}$$

Therefore, \$3.88/klb is the steam purchase price that will allow the absorption chiller to compete with comparable centrifugal chillers to provide equivalent campus chilled water demands, when the centrifugal units purchase electricity at \$0.10/kWh. As the cost of generating steam by the cogeneration units presented above is \$5.14/klb, with the particular set of parameter used in this study case it is more economical to run the electric chiller than the single-effect absorption chiller. However, it is less costly to use the steam in the absorber than to dump it in a steam condenser.

Electric Centrifugal Chillers

The electric centrifugal chillers appear on the analysis in order to establish a benchmarking relationship between the amount of steam consumed by the single-effect absorber and the amount of electricity required by electric centrifugal chillers, for the same amount of delivered cooling effect. Should the need arise for not operating the absorber, an equivalent amount of cooling would have to be provided by the comparable electric centrifugal chillers. The average efficiency of the electric chillers employed in this analysis is 0.70 kW/ton.

In the break-even analysis, the expense per ton-hour is $0.70 \text{ kWh/ton-h} \times \$0.10/\text{kWh} = \$0.07/\text{ton-h}$ and the revenue is valued at $\$0.11/\text{ton-h}$.

Break-Even Analysis

The object of this case study analysis is to compare the economic advantage of the following two scenarios:

- 1. Operating both cogeneration units and the single-effect absorption chiller
- 2. Operating only one cogeneration unit and firing its turbine exhaust duct burner to meet campus steam demand

Economic Model

For the two scenarios listed above, the expenses and revenues are summarized in Tables 22-7 and 22-8 for a 1-hour period at constant campus steam consumption. These tables reflect the economic model for this case study.

Tables 22-9 and 22-10 depict the calculations based on equipment data for this case study, with the following notations:

- R_g is gas rate ($\$/\text{m}^3$)
- R_e is electricity rate ($\$/\text{kWh}$)
- R_s is steam rate ($\$/\text{klb}$)
- R_c is cooling rate ($\$/\text{ton-h}$)

Note that for comparison purpose, the electric chiller revenue is equal with the revenue for the absorption chiller, and the electric chiller expense is the corresponding cost for electric energy used to generate the same cooling output as the absorber.

Results of Analysis

In Tables 22-7 and 22-8, the net revenue for scenario 1 is equal to (Revenue 1 – Expense 1) and for scenario 2, is equal to (Revenue 2 – Expense 2). The break-even point (in lb/h campus steam) between scenario 1 and scenario 2 is where the net revenues are equal, namely:

$$(\text{Revenue 1} - \text{Expense 1}) = (\text{Revenue 2} - \text{Expense 2})$$

Equipment	Item	Expense per Hour	Revenue per Hour
Cogeneration units	Natural gas	Cogen gas cost	
	Electricity		Electricity revenue
HRSg	Steam		Campus steam revenue
Cogeneration units		Fixed cost	
Absorption chiller	Steam	Absorber steam cost	
	Cooling energy		Campus cooling revenue
Total		“Expense 1”	“Revenue 1”

TABLE 22-7 Evaluation Model for Two Cogeneration Units and Absorption Chiller

Equipment	Item	Expense per Hour	Revenue per Hour
Cogeneration unit	Natural gas	Cogen gas cost	
	Electricity		Electricity revenue
HRSG	Steam		Campus steam revenue
Cogeneration unit		Fixed cost	
Duct burner	Natural gas	HRSG gas cost	
	Steam		Campus steam revenue
Electric chiller	Electricity	Chiller electricity cost	
	Cooling energy		Campus cooling revenue
Total		"Expense 2"	"Revenue 2"

TABLE 22-8 Evaluation Model for One Cogeneration Unit with Duct Burner HRSG

Equipment	Item	Expense per Hour	Revenue per Hour
Cogeneration units	Natural gas	$R_g \times 1710 \text{ m}^3 \times 2$	
	Electricity		$R_e \times 4700 \text{ kWh} \times 2$
HRSG	Steam		$R_s \times 50 \text{ klb}$
Cogeneration units		Fixed cost	
Absorption chiller	Steam	$R_s \times (50 \text{ klb} - \text{campus steam})$	
	Cooling energy		$R_c \times (50 \text{ klb} - \text{campus steam})/18 \text{ lb/ton-h}$
Total		"Expense 1"	"Revenue 1"

TABLE 22-9 Data for Two Cogeneration Units and Absorption Chiller

Equipment	Item	Expense per Hour	Revenue per Hour
Cogeneration unit	Natural gas	$R_g \times 1710 \text{ m}^3$	
	Electricity		$R_e \times 4700 \text{ kWh}$
HRSG	Steam		$R_s \times 25 \text{ klb}$
Cogeneration unit		Fixed cost	
Duct burner	Natural gas	$R_g \times (\text{campus steam} - 25 \text{ klb}) \times 31.35 \text{ m}^3/\text{klb}$	
	Steam		$R_s \times (\text{campus steam} - 25 \text{ klb})$
Electric chiller	Electricity	$R_e \times (50 \text{ klb} - \text{campus steam})/18 \text{ lb/ton-h} \times 0.7 \text{ kWh/ton-h}$	
	Cooling energy		$R_c \times (50 \text{ klb} - \text{campus steam})/18 \text{ lb/ton-h}$
Total		"Expense 2"	"Revenue 2"

TABLE 22-10 Data for One Cogeneration Unit with Duct Burner HRSG

or

$$(\text{Revenue 1} - \text{Revenue 2}) = (\text{Expense 1} - \text{Expense 2})$$

It should be noted that

- The fixed costs are the same in Expense 1 and Expense 2.
- The revenues from campus steam are the same in Revenue 1 and Revenue 2.
- The revenues from chilled water are the same in Revenue 1 and Revenue 2.

When the revenues and expenses are subtracted as shown, the net result for fixed costs, steam revenues, and chilled water revenues are all equal to zero. This shows that the break-even point is not dependent on the cost of the fixed maintenance charges, nor on the steam or chilled water purchase cost from the CUP to the campus and thus can be ignored for the purposes of this analysis.

In Tables 22-9 and 22-10, the unknown variable is “campus steam”. Solving the equation for the break-even point between the absorber (1) and turbine exhaust duct burner (2) modes with the natural gas and electric rates noted in this study, results in a campus steam load of 29,415 lb/h. Accordingly, should the campus steam load exceed this value, it is more economical to run both cogeneration units and dump steam to the absorber. For campus loads below 29,415 lb/h, it is more economical to run one cogeneration unit with its turbine exhaust duct burner.

Utility Rate Impact on Break-Even Point The break-even point between absorber operation and duct burner operation is 29,415 lb/h only for the electricity and gas rates selected for illustration in this case study. The surface graph (Fig. 22-2) below shows

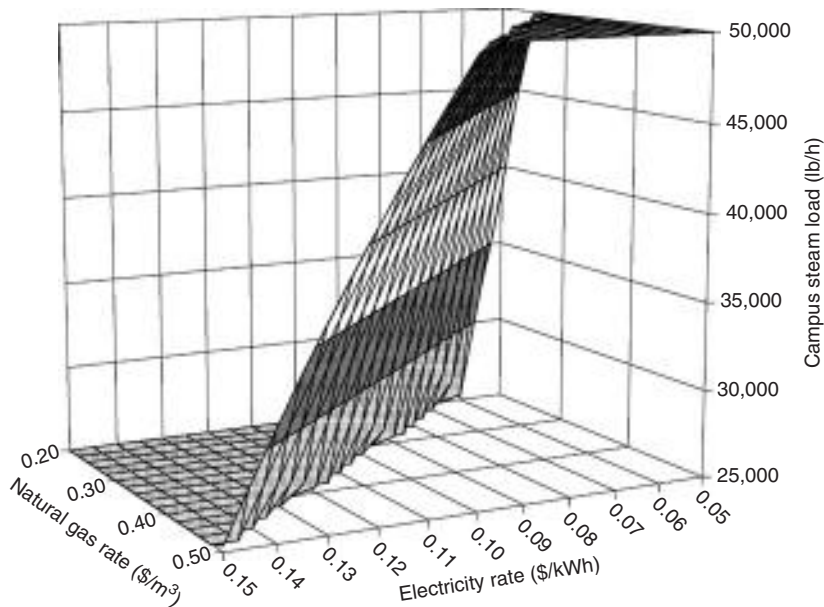


FIGURE 22-2 Break-even analysis versus natural gas and electricity rates.

how the break-even point will shift as electricity and gas rates change. Generally, the break-even point will rise with rising gas prices and fall with rising electricity prices. The graph also shows that the break-even point will remain constant if the ratio of gas-to-electric prices remains constant.

Net Result of Absorber versus Duct Burner Operation Figure 22-3 below is created with the baseline gas and electric rates noted in this study. It is a plot of the revenue advantage of absorber operation compared to duct burner operation, as the campus steam load changes. The break-even point is \$0 at 29,415 lb/h.

The revenue advantage, in dollars per hour, increases with increasing load above 29,415 lb/h. The negative absorber advantage below the break-even point is actually the advantage of duct burner operation over absorber operation.

Not shown is the CHP plant operation below 25,000 lb/h, where one cogeneration unit should be shut down, and the absorber should be used. In this case, the comparison can be performed between operating a cogeneration unit and the absorber against operating a supplementary boiler. The production cost of steam from a conventional boiler is higher than from a cogeneration unit so that it is more economical to operate the cogeneration unit and the absorber but not the supplementary boiler.

Figure 22-4 shows three-dimensional versions of Fig. 22-3 for 25,000 lb/h and 50,000 lb/h, as a function of above gas and electric rates. Where a point on the surface has a positive dollar value, two cogeneration units plus absorber appears more advantageous. For negative values, duct burner operation is preferred. Comparing the two graphs, higher steam demand appears to favor absorber operation at higher gas prices and lower electricity prices.

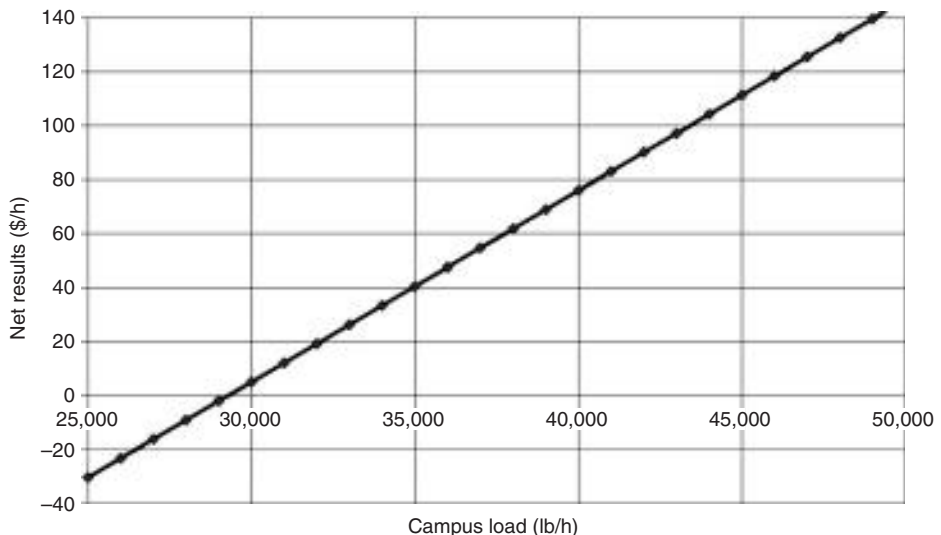


FIGURE 22-3 Net result of absorber versus duct burner operation.

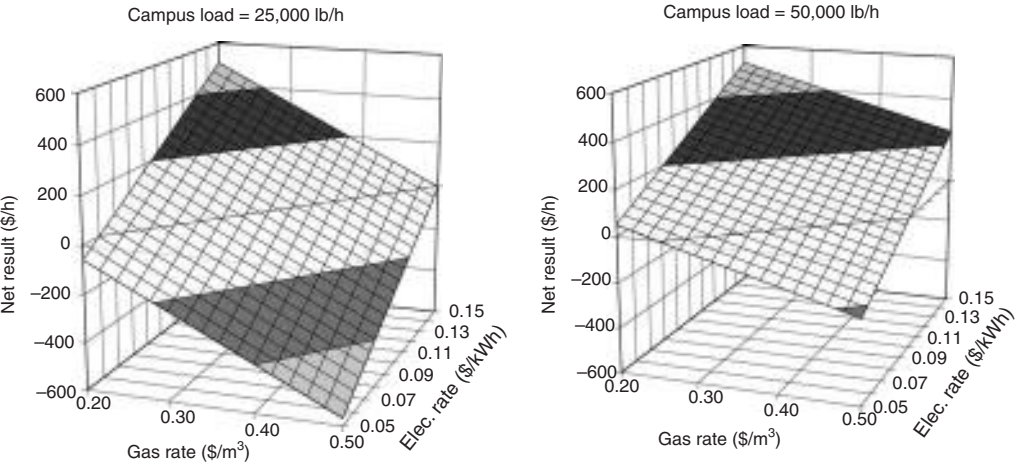


FIGURE 22-4 Net result versus natural gas and electricity rates.

Conclusions

- The break-even point between operating two cogeneration units or one cogeneration unit and a duct-fired HRSG is approximately 29,415 lb/h.
- When the campus steam load exceeds 50,000 lb/h, both cogeneration units should be run at full capacity with the HRSG duct burners fired as required.
- When the campus steam load falls below 50,000 lb/h (or the combined cogeneration steam capacity with unfired HRSGs), but above the break-even point of 29,415 lb/h, all the excess cogeneration steam should be used to run the single-effect absorption chiller in the chiller plant.
- When campus steam demand falls below the break-even point of 29,415 lb/h, one cogeneration unit should be shut down. However, the remaining cogeneration unit should be operated by firing the HRSG duct burner as required to meet campus demand but with no steam sent to the absorber.
- When campus steam demand is less than 25,000 lb/h (the output of one cogeneration unit with unfired duct burner), all the excess cogeneration steam should be used by the absorption chiller.
- The break-even point between one cogeneration unit operating with the absorber, and a conventional boiler, is below the boilers minimum firing rate, therefore, in all cases, a cogeneration unit should be operated.
- If the second cogeneration unit is operated when campus steam demand is between 25,000 lb/h and the break-even point, this study identified a method for calculating the additional cost burden to CUP.

CHAPTER 23

Case Study 5: Governmental Facility— Mission Critical

Michael A. Anthony

Just as CHP makes a BTU work twice in a single process, can we make the financing for energy conservation work twice on behalf of homeland security? There is synergy, though subtle, between the issues. Innovative regulation to merge these objectives is tracking in the public sector for facilities related to safety, disaster response and recovery. Consider the following.

1. In Connecticut, the Departments of Education and Emergency Management and Homeland Security have been directed to establish a municipal renewable energy program that gives priority to grants for disaster relief centers in high schools.¹
2. In New York, proposed legislation allows for the New York State Energy Research and Development Authority to make financial assistance available for development of facilities of refuge to be used in disaster response and recovery.²
3. The City of Chicago has undertaken a pilot project for a new generation of police stations that includes modular CHP-based prime movers.²
4. The Town of Epping, New Hampshire, has installed microturbines in its wastewater treatment plant.³

Power security is not a purely technical problem, nor one that can be solved by financing individual point solutions. High nine reliability, common in e-business, is now influencing the rehabilitation of emergency management facilities through a new requirement that appears in Article 708 of the 2008 National Electric Code. When fully realized, the Critical Operations Power Systems (COPS) Article 708 will penetrate silos of thinking about power security at the state and local level (a detailed definition of COPS can be found in the Glossary).

As seen in other chapters, fairly narrow conditions must be met for CHP to be successful; a prospect that is common for any complex, hybrid, integrated system. The price at which natural gas-fired cogeneration is competitive with electricity depends primarily on the local tariff, the size of the facility, the thermal load of the building, and other financial incentives available from federal and state agencies.

Cogeneration systems with a backup power feature have been common for quite some time now; many given impetus in Section 210 of the original 1978 federal Public Utilities Regulatory Policies Act. The backup system remains enabled in either island-mode, when the CHP plant supplies all energy to a facility; or when the plant runs in parallel with the macrogrid utility, supplying only partial energy to a facility. The recovery of waste heat for COPS offers an advantage to emergency management facility generation close to loads but at the same time adds significantly to avoid cost analysis because of the need to simultaneously meet requirements for electricity, heat, and cooling for the homeland security mission.

Risk Management

Providing security is one of the core functions of government that protects the brand value and reputation of a community. City managers know that the ISO-rating of a fire department affects economic viability because many businesses are sensitive to a host community's ability to respond to disaster. Local governments must weigh the capital costs of risk avoidance against the contingent benefits of insurance against such risks (i.e., the consequences to a community if it is not so insured). These latter avoided costs are used as estimates of the benefits of disaster insurance.

But CHP has risks of its own, not the least of which are the following:

- *Market risk.* A primary and secondary fuel must be available and affordable. Switching between them must be seamless. The fuel cost of aggregating thermal loads has to be less than the cost of electricity to individual buildings plus the cost of individual building boilers and chillers.
- *Construction risk.* When public money is involved, incremental change is the path of least resistance. Partial retrofit projects in existing square-footage are more difficult than new construction but may be the only practical way to show diligence and progress toward conformity to applicable building codes like the NEC.
- *Regulatory and financing risks.* The cost of money at the point of conception and regulatory measures that change marginal tariffs on energy and emissions. PURPA was followed by EPAACT 1992 and EPACT 2005. Energy policy shapes the market; the energy market shapes policy.

Contemporary risk management diversifies risk with a mix of financial and engineering approaches. A prudent jurisdiction invests in insurance to the point that the marginal cost of the next most efficient emergency measure equals the expected value of the marginal benefits insurance would buy. Risks that cannot be controlled must be allocated among stakeholders in a logical way; often the jurisdiction is in the best position to bear the risk.

At first glance, CHP seems to set up the possibility of increased risk because of the interdependence of natural gas, water, and electricity. While power will only be available from cogeneration only when thermal load is present, CHP can at least offset the capital costs of critical operations power systems needed by the municipality anyway.

Two Case Studies

The extension of cogeneration into backup power systems requires an investigation into the complex interplay of policy, economic and technical issues of so-called trigeneration, and microgrid development.

There is an absence of actual case histories that are publicly available on the specific application of CHP to emergency management facilities; however, this chapter explores the central conceptual promise of CHP for emergency management facilities using two studies as benchmarks:

- An economic case study sponsored by the U.S. Environmental Protection Agency, based upon actual field records from a joint Pacific Gas and Electric (PG&E) and Electric Power Research Institute (EPRI) research project. The results demonstrate a 16.9 percent improvement in simple payback in a 1500-kW CHP system with backup power capability versus the simple payback of the same CHP system without backup power capability.
- A generic reliability study from the Institute of Electrical and Electronic Engineers (IEEE) based upon actual failure rate data from U.S. Army Corps of Engineers Power Reliability Enhancement Program. The results reveal that a 1000-kW radial system with CHP cuts the average forced hours of downtime per year in half as the same system without CHP.

Many believe that the electricity markets need to be redesigned before wide-scale distributed resource technologies such as CHP become dramatically more common. Others believe that power security should come first. Still others believe that market redesign and security are inextricably linked. If the target environment for homeland security requires the installation of backup generation anyway, a conversation about the practical use of a tried-and-true technology like CHP is responsible stewardship.

The Homeland Security Objective

Central to public policy will be consideration of the social impact of town-center, economic development, and emergency management districts since their formulation shapes energy infrastructure development. In many American cities, energy infrastructure follows the geometry of the city. When the objectives of homeland and energy security are handled together, urban planners have to think a little harder about whether population aggregations ought to be guided around the availability of electric power for the next 100 years. Conceptually, this is no different from the way cities oriented themselves around transportation routes in the past.

The scope of Article 708 is as follows:⁴

Critical operations power systems are those systems so classed by municipal, state, federal, or other codes by any governmental agency having jurisdiction or by facility engineering documentation establishing the necessity for such a system. These systems include but are not limited to power systems, HVAC, fire alarm, security, communications, and signaling for designated critical operations areas.

FPN No. 1: Critical operations power systems are generally installed in vital infrastructure facilities that, if destroyed or incapacitated, would disrupt national security, the economy, public health or safety; and where enhanced electrical infrastructure for continuity of operation has been deemed necessary by governmental authority.

Conformity starts with a risk assessment, identifies single point of failures, and establishes a program for periodic functional performance testing of all of interdependent systems. Achieving higher “nines” requires the elimination of all single points of failure with a mix of module level and system level redundancy. The local authority having jurisdiction has to inspect and approve the effective “nameplate availability” of the COPS.⁵

A new term in the NEC—*designated critical operations area (DCOA)*—refers to the actual building square-footage of supplied power from the COPS. In this chapter, we will discuss COPS as being part of a DCOA that is part of a larger emergency management agency (EMA) facility or a multibuilding emergency management district. Within this mix, joint police and fire stations are common; so are extensions of critical information systems to run government operations during a disaster.

A question that will have to be answered city by city, is whether colocation of emergency management assets is too far out the risk curve? Figure 23-1 is a concept sketch

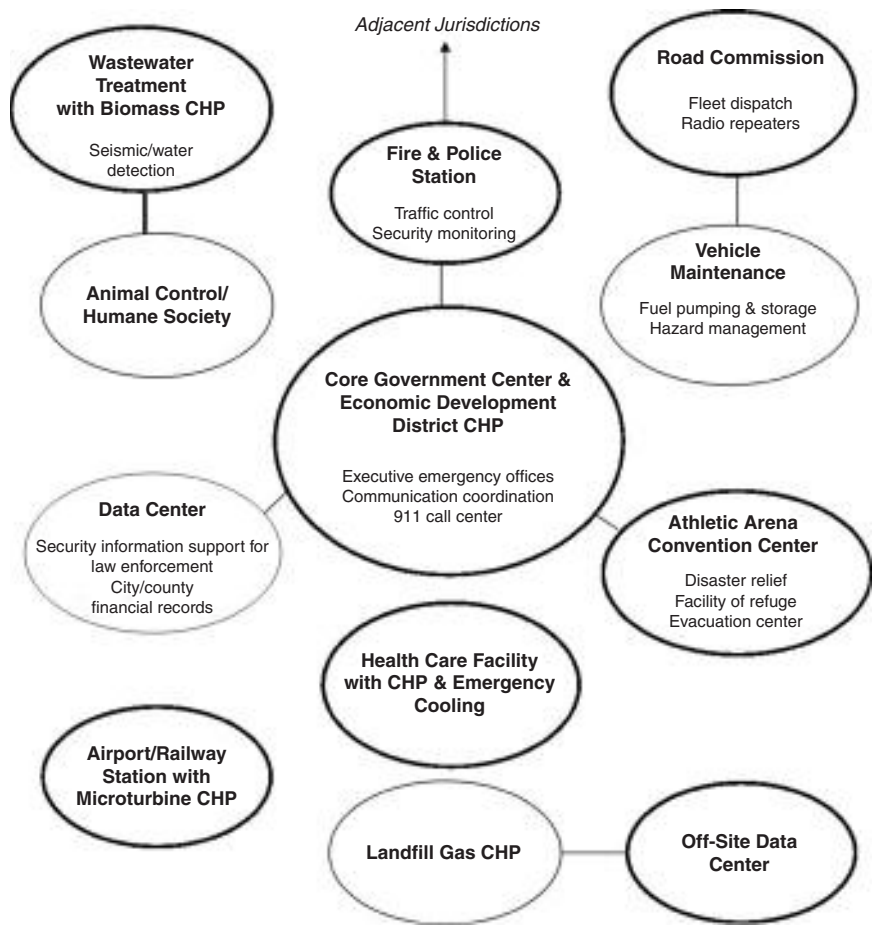


FIGURE 23-1 Schematic of countywide critical operations.

that shows these assets spread around (Facilities with the prospect of an appropriate thermal load are identified in bold lines.). Further, Fig. 23-1 provides a schematic of countywide critical operations: The risk mitigation plan required in Section 708.64 of the 2008 National Electric Code should encompass many emergency management assets within single building premises as well as assets that are widely scattered but networked together as a single operation. Single point of failure risk is reduced but a network of distributed COPS assets increases the capital costs.

While Article 708 only requires a 3-day supply of fuel, urban planners and engineers should contemplate the development of COPS cities with a 30-day major regional contingency as a benchmark. Proximity to primary and secondary fuel supplies is essential. Since cooling water is needed to generate energy; and energy is needed to deliver water, the availability of water needs to be a factor in the risk equations. These benchmarks are similar to 10- and 100-year benchmarks civil engineers use to design storm water infrastructure.

The Energy Conservation Objective

Among energy professionals, concern about fuel cost and stability in any CHP scheme is never far below the surface. Spot market phenomena in gas and electricity—the so-called “spark spread”—can seriously unbalance the energy budget of many local government agencies in a single 15-minute outage or extreme weather day.

The most cost-effective cogeneration systems operate at full output 24/7, though they may only generate a portion of the total electric and thermal need—commonly in the range of 50 to 80 percent. Capital and operation and maintenance (O&M) costs per unit output increases as the facility size decreases, lowering the natural gas prices required for breakeven with electricity. The thermal load factor determines the amount of electricity that can be produced assuming the cogeneration unit operates to supply base load thermal demand.

CHP-COPS can be used by the emergency management facility as a peak-shaving distributed resource of its own. The capacity of the prime mover can be scaled to the demand profile of the COPS, and the demand of other electrical loads in the facility. One financial strategy involves consuming kilowatthours (energy) from the macrogrid but reducing kilowatt demand (power) with the local microgrid. This arrangement can be cost-effective when the microgrid produces only 2 to 3 percent of the kilowatthour needs but significantly reduces kilowatt demand.

How significant? One rule of thumb is that any more than 20 to 25 percent of the COPS demand for peak reduction purposes may not be economically justifiable. (Because on-site kilowatthours are more expensive than macrogrid, central station kilowatthours)

COPS Integration with District Heating

A district energy system for government center critical operations power can meet economic goals that individual building installations usually cannot. District energy systems can use a variety of fuels such as oil and natural gas, whichever is most competitive at the time. Central management of operations and maintenance offers economy of scale and the lowest delivered cost and emissions impact.

In some cost structures, the normal and alternate supply is a combination of fired and unfired boilers, steam and gas turbines, prime-rated diesel gen-sets that provide

flexibility and reliability to meet demand. The ability to adjust generation levels and still maintain required steam or gas pressures and temperatures is very much a function of the district's design.

In some cost structures, the CHP system would provide electricity to the DCOA on a continuous basis, resulting in daily operating cost savings. In this type of configuration, the CHP system is sized to meet the base thermal and electric needs of the facility. When the macrogrid fails, the COPS generators would switch to the electric riser that feeds COPS loads only. The absorption chiller would continue to produce cooling, which would be directed only to data center loads and specific areas where disaster management personnel require air-conditioning.

In other cost structures, supplemental power from the grid would serve the DCOA's peak power needs on a normal basis and would provide the entire facility's power only when the CHP system is down for planned or unplanned maintenance.

The 2008 version of Article 708 does not directly address microgrid configurations in which CHP provides all on-site power needs. Though recent revisions of the NEC demonstrate that its authors have adapted to the gathering pace of innovation in distributed resource technologies, the NEC is still written around the assumption of a macrogrid "serving utility", with specific requirements for service switchgear, subject to the requirements of the state public utility commission for safety and reliability. The availability of the primary on-site source, and the backup system, must be approved by the authority having jurisdiction as meeting the availability requirements of Article 708 and its related annexes in the NEC.⁶

In the past 10 years, major regional contingencies proved district steam systems to be reliable to about 99.98 percent. District heating systems were the only utilities to provide continuously uninterrupted service during:

- The natural disasters of the Loma Prieta earthquake (7.1 Richter scale) in San Francisco in 1989
- The massive Ottawa Ice Storm in Montreal during 1998
- The destructive 6.8 Nisqually earthquake that shook Seattle in 2001

In 2006, 17 of the top 20 hospitals in America, according to U.S. News & World Report, were served by district energy systems.⁷ Many colleges and universities, during the August 2003 major regional contingency in the northeast United States and Canada, were able to provide a limited amount of power equipment in their host communities. If the trends described at the beginning of this chapter continue, educational facilities will be called upon to play a larger role in homeland security.

District heating is a long-term commitment that fits poorly with a focus on short-term returns on investment. It has to compete with the established gas grid which offers point-of-use heating to most buildings. It requires that politicians, planners, developers, market actors, and citizens cooperate on a range of issues, but offers important benefits as outlined in this book.

Prime Mover Possibilities

Most backup gen-sets are installed to meet the requirements of NFPA life safety codes and are limited to about 200 hours per year before overhaul. Most of these life safety gen-sets are rarely used; with most of the hour run-up due to mandatory testing. The

most rigorous performance requirement is for a gen-set power to be available for emergency egress lighting within 10-seconds and run for 90-minutes; a requirement that is sometimes met with a static reserve such as a battery. Other life safety infrastructure such as fire pumps, elevators, and fire alarm systems demand more from the prime mover. As long as life safety requirements are met, the NEC permits the same prime mover(s) to be used to supply backup power to other optional standby loads.

An idealized emergency management district electric system, with renewable distributed resources and load classes integrated with CHP, is shown in Fig. 23-2. Requirements for the complex SCADA, signaling and control systems are not shown here but guidance on them appears in Annex G of the 2008 NEC. Additionally, Fig. 23-2 provides a concept diagram for CHP in an emergency management facility: New National Electric Code Article 708—Critical Operations Power Systems requires that emergency management facilities tool up for 100 percent loss of utility supply. Per 708.20(F)(3) a

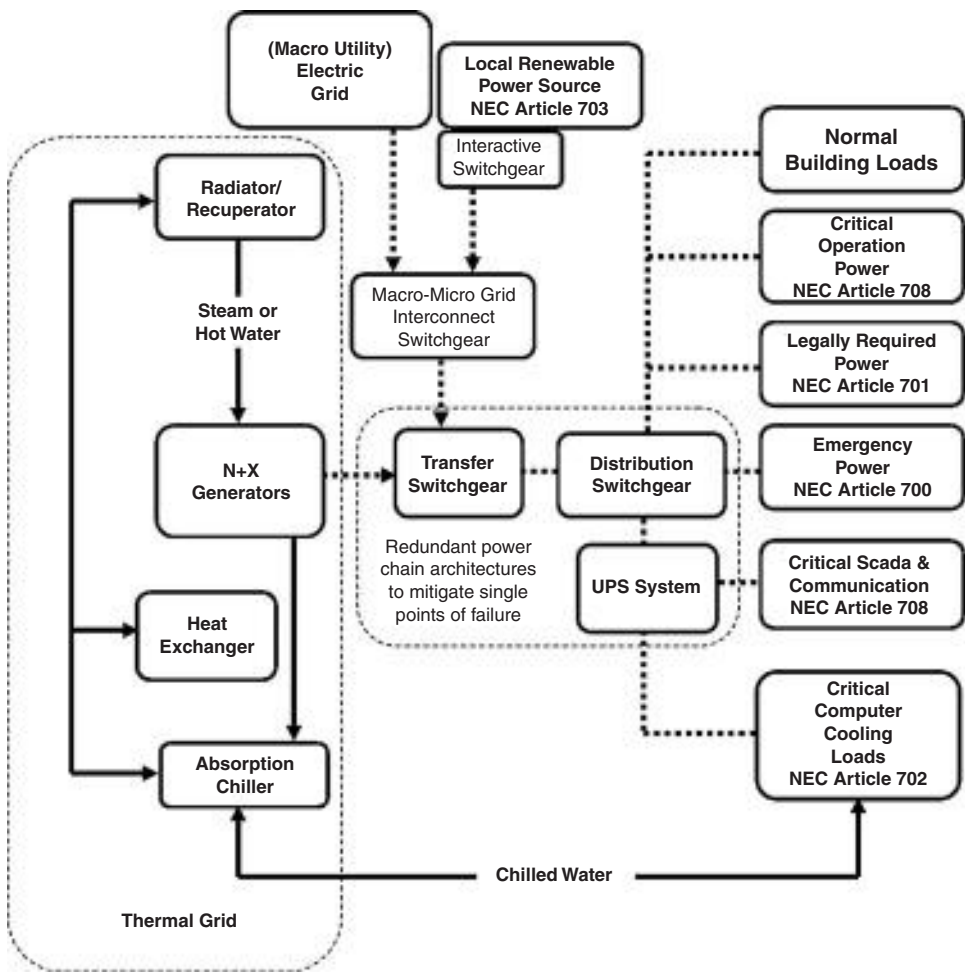


FIGURE 23-2 Concept diagram for CHP in an emergency management facility.

second utility power source does not count as redundant supply. On-site fuel must be available for 3 days.

If the average electric demand is

- Less than 250 kW then the most likely technology will be a small reciprocating engine gen-set or a microturbine gen-set, or possibly a fuel-cell
- Greater than 250 kW to about 800 kW the primary option is a reciprocating engine
- Between 800 kW to about 5 MW, either a reciprocating, combustion or steam turbine is an option

There is a wide range in efficiency of these units. Diesel gen-sets are highly scalable and less expensive than natural gas on a kilowatt basis. These packaged units are factory built and delivered to site as complete units that make installation a relatively simple matter. Diesel systems, however, especially those above 1000 kW, are harder to permit, are limited in run hours in most areas, and have on-site fuel storage issues.

Steam turbine generators for CHP systems that use natural gas as primary fuel in a steam boiler can operate upward of 8000 hours per year. Some microturbines can run up to 20,000 hours without substantial maintenance. Microturbines have found their place among distributed resource technologies; a fact likely attributable to its status as the only CHP technology currently eligible for U.S. federal tax credits.⁸

Gen-sets may be operated at the standby rating for the duration of a power outage but should not be used at the standby rating for continuous CHP operation. Generators for standby use are frequently operated at a higher output and temperature rise than are those for continuous use. Accordingly, the gen-sets can be classified according to the fuel type, the load they carry and how long they can carry it. Some gen-sets can run longer with de-rating factors (see Chap. 12 for more details).

A standard design approach features two or more smaller units as part of a building block concept, in which additional units are added as capital is made available; thus simplifying maintenance. When utility power fails, and the CHP system is balanced, one or more generators will automatically start and be ready to pick up swing load. While the lead generator continues to run, another generator is brought into synchronism, paralleled automatically with the first.

In installations where there is a high ratio between the largest single generator and total generation, frequency disturbances can be caused by a forced outage of a generator. For such a disturbance, the frequency variation can be controlled with the help of other synchronous reserves.

Black Start

A CHP scheme that hosts a COPS will require some contingency arrangements to restart in the event that rotating equipment comes to a standstill. The process of restoring a stopped power system is commonly referred to as “black start.” On the macrogrid, a black start involves isolated power stations starting individually and gradually being reconnected to each other in order to form an interconnected system again.

Large diesel gen-sets are provided with much smaller gasoline engines for starting. Smaller gas turbines can be started by electric motors supplied from station power batteries backed up with black start generators. One gas turbine started by an internal combustion engine will be able to start other gas turbines at the same location. One or two diesels or gas turbines will be sufficient to start a much larger steam turbine unit.

Black starts are avoided with load-shed controls that maintain the balance between generation and load. The necessity for black start generating equipment in a CHP-COPS must be figured into all cost analyses. An auxiliary generator system set up for black start looks a lot like the idle emergency gen-set that a CHP-based COPS is intended to replace in the first place. In some applications, the smaller black start generating equipment may be used to offset the cost of higher capacity emergency generating equipment as discussed in the next section.

Emergency Power

It sometimes comes as a surprise to many in the building industry that the requirement for emergency power does not originate in the National Electric Code. As an installation code, the NEC only provides guidance on leading safety practice. Whether or not an emergency generator, or other backup source is needed for fire pumps, egress lighting, fire alarm protection systems, or elevators is provided by NFPA 101, the Life Safety Code®. A related standard, NFPA 110, Standard for Emergency and Standby Power Systems, is adopted by reference into the NEC and the Life Safety Code.⁹ NFPA 110 classifies backup power systems according to class, type, and level which distinguishes their character according to occupancy type, the number of seconds required to start, and the number of minutes required to operate, respectively. Any CHP system must be set up so that power balance is possible within the time frames required by the application.

According to NEC Section 700.5, a backup or alternate power source may be used for peak-shaving as long as it has the capacity to supply emergency, legally required standby, and optional standby loads first. Whenever the backup (alternate) source is temporarily out of service, a portable or temporary alternate source must be available. A variation of this impairment mitigation requirement appears in the best practice documents of other industries.

To summarize: CHP-COPS can increase availability and security by

- Reducing the size of the emergency generators by allowing noncritical loads to be supplied from the CHP system.
- Reducing the number and duration of emergency generator starts.
- Allowing more “business critical” loads to be kept on during utility grid outages or disturbances. If there is a disturbance on the grid, the CHP prime mover will adjust to mitigate it; if there is a voltage transient on the owners electrical system (such as from a large motor start) the grid serves to dampen the mitigate that transient.

Interconnection

Interconnection issues pervade all sizes of independent generation. In addition to operator safety and net metering concerns, all interconnections must accomplish smooth, in-phase synchronous transfers between grid-connected and island-mode.

Utility engineering staffs are sensitive to interconnection technical details because so much of the last mile of the macrogrid is still configured in central station fashion. Traditional, macrogrid utilities operate in an economic space in which prices are administered; not discovered, and the cost of making changes to the last mile of electrical distribution to accommodate customer-owned CHP has to be figured into the tariff approved by the public utility commission.

As with many U.S. regulatory issues, interconnection is seriously complicated because utility regulation resides, in large part, at the state level. A CHP project would be responsible for the reliability effects and costs of all utility system upgrades associated with its particular interconnection. These effects are determined by the utility's studies of each project, based on assumptions made with regard to the timing of any other distributed resource projects ahead of it in the queue.

Final reliability requirements and cost responsibility depend on which projects are ultimately built. As these often may not be the same projects assumed in the study, this condition adds to uncertainty and delays. Some public service commissions have queuing management protocols (such as clustering or class-year studies) that aim to mitigate the problems caused by the project-by-project queue approach.

The mother standard for micro- and macrogrid interconnection is the IEEE 1547-series of documents, some of which are still in draft mode. During IEEE 1547 development, industry thought leaders recognized that islanding parts of the macrogrid's distribution system could improve reliability of the major control areas of the U.S. grid. The 1547-series of standards provide alternative approaches and good practices for the design, operation, and integration of the microgrids and covers the ability to separate from and reconnect to part of the utility while providing power to the islanded local power systems.¹⁰

Other Considerations

- Local enforcement authorities determine whether the natural gas supply is available enough to be treated as an "on-site" fuel source.
- Any COPS feasibility study should include information about other generators in the area. Sometimes information about other backup generators are registered with the fire department rather than the buildings or air quality/permitting departments.
- Most urban areas limit the hours that diesel generators can be operated each year because of their NO_x and SO_x emission levels. Peak-shaving may require a separate air quality permit.
- Backup fuel supply chains share with the electric and gas network, the basic feature of congestion. When primary fuel supply chains bind, the same will be seen in the prices of backup fuel supplies.
- Dual-fuel generators are ideal for COPS and are the thin end of what could be a big wedge for CHP. A number of tests are underway around the country using dual-fuel diesels fired with 80 percent natural gas and 20 percent diesel oil. Some European manufacturers offer gas/diesel packages capable of continuous operation on a 90/10 mix.¹¹

Electrical Load Classes

Throughout this chapter the term "backup" has been used to describe a family of technologies which carry load when the normal (primary) source of power is absent. When the backup source can carry full load, the term "alternate" source is used. A common vocabulary for the subtle differences in electrical load classes, however, has eluded thought leaders in IEEE and NFPA leading practice committees. There is ambivalence

about whether precise terminology is necessary for practitioners who would understand such distinctions in a specific application context.

But the distinction among load classes is significant. It is the main parameter for matching electric to thermal load. In the most likely scenario, in which the EMA has only enough funding to make incremental changes in a legacy DCOA, the separation of load classes is necessary to keep capital and operational budgets honest. Consider the following:

- The use of the word “emergency” in the NFPA universe of standards that cover building safety is not coordinated with the use of the same word by the IEEE in documents that deal with power systems at all voltage levels.
- The Federal Energy Regulatory Commission (FERC) uses the term “essential” in its official rulings while the Joint Commission on the Accreditation of Healthcare Organizations reserves that term for a subclass of loads in hospitals.
- The National Electric Reliability Council uses the word “critical” in its Critical Infrastructure Protection standard but the same word is reserved for a subclass of loads in hospitals in Article 517 of the NEC.
- FERC refers to four classes of service to qualifying facilities: supplementary power, interruptible power, maintenance power, and backup power.
- The term “mission critical” itself is copyrighted.

Without these distinctions it is possible for these technologies to fail to meet capacity, reliability, or cost criterion.

Whether or not the CHP system supplies all or part of the DCOA or EMA facility electric load, the COPS loads must be isolated from the rest of the facility’s noncritical loads. The critical load isolation approach can be manual or automatic and can be configured to incorporate dynamic prioritization of load matches to the CHP system capacity.

In a peak-shaving or peak-sharing regime, the controls should include priority interrupt logic that automatically suspends peak-shaving upon sensing a loss of adequate power to the emergency loads. The same logic initiates retransfer or disconnect the peaking shaving loads from the emergency or standby source to enable immediate transfer of the emergency loads to the backup source. This reduces transfer time. Since the emergency or standby power source is already running, the outage to the emergency loads is significantly reduced.

The load to be tripped in a load-shed scheme should be large enough to compensate for the maximum anticipated overload at one load-shed step. Choosing the number of load-shed steps must be coordinated with the load and time required for each of the systems shown in Table 23-1. When the core concepts of NEC Chapter 7 Special Systems are placed side by side, it is easier to see the gap filled by Article 708. Within buildings, these different power systems must be isolated from each other—typically by dedicated switchgear, a separate conduit system, and possibly by a fire-resistant central chase that ensures the integrity and survivability of power and control wiring.

More load than necessary may be disconnected for a less severe overload by this strategy. On the other hand, it may result in a coordination problem among protective relays if too many load-shed steps are involved. A typical load-shed strategy may only

Title	Scope or Definition	Fine Print Note
700 Emergency Systems	These systems are intended to automatically supply illumination, power, or both, to designated areas and equipment in the event of failure of the normal supply, or in the event of accident to elements of a system intended to supply, distribute, and control power and illumination essential for safety to human life.	FPN No. 3: Emergency systems are generally installed in places of assembly where artificial illumination is required for safe exiting and for panic control in buildings subject to occupancy by large numbers of persons, such as hotels, theaters, sports arenas, health-care facilities, and similar institutions. Emergency systems may also provide power for such functions as ventilation where essential to maintain life, fire detection and alarm systems, elevators, fire pumps, public safety communications systems, industrial processes where current interruption would produce serious life safety or health hazards, and similar functions.
701 Legally Required Standby Systems	These systems are intended to automatically supply power to selected loads (other than those classed as emergency systems) in the event of failure of the normal source.	FPN: Legally required standby systems are typically installed to serve loads, such as heating and refrigeration systems, communication systems, ventilation and smoke removal systems, sewage disposal, lighting systems, and industrial processes, that, when stopped during any interruption of the normal electricity supply, could create hazards or hamper rescue or fire-fighting operations.
702 Optional Standby	These systems are intended to supply power to public or private facilities or property where life safety does not depend on the performance of the system. Optional standby systems are intended to supply on-site generated power to selected loads either automatically or manually.	FPN: Optional standby systems are typically installed to provide an alternate source of electric power for such facilities as industrial and commercial buildings, farms, and residences and to serve loads such as heating and refrigeration systems, data processing and communications systems, and industrial processes that, when stopped during any power outage, could cause discomfort, serious interruption of the process, damage to the product or process, or the like.
708.2 Critical Operations Power Systems (COPS)	Power systems for facilities or parts of facilities that require continuous operation <i>for the reasons of public safety, emergency management, national security, or business continuity.</i> (Emphasis added.)	FPN No. 1: Critical operations power systems are generally installed in vital infrastructure facilities that, if destroyed or incapacitated would disrupt national security, the economy, public health or safety; and where enhanced electrical infrastructure for continuity of operation has been deemed necessary by governmental authority.

Source: Copyright NFPA, Quincy, Massachusetts.

TABLE 23-1 Overview of NEC Chapter 7 Articles

have three load-shed levels (though up to 32 levels are widely available in some control packages). One rule of thumb suggests loads can be shed in decrements no greater than 30 percent of normal load.

Meeting all the criteria for federal–state matching funds in multifunction buildings will involve some extremely testing financial acrobatics. Where this is not easily accomplished, internal accounting segregation of the costs of various types of infrastructure may achieve many of the purposes served by physical segregation of load classes.

Reliability Worth

An assessment of CHP hosting critical operations power starts with consideration of the nature and duration of the outage. In reliability studies, generally; there are two common baselines:

- *Momentary*: 5 to 10 seconds, maximum
- *Extended*: 10 seconds, minimum

The effects of momentary outages can be mitigated with equipment such as flywheels or batteries. The effects of extended outages can be mitigated by getting the emergency management facilities high on the regional restoration order rankings of the local utility (if it is not already). A CHP-COPS feasibility study should include consideration of these approaches.

The EPA Economic Study

A case study—keeping reliability considerations constant—comes from research prepared by the U.S. Environmental Protection Agency.¹² In this study, the value of reliable service was determined for a 1500-kW CHP system running in island mode for a representative commercial customer of the PG&E. When power delivery is disrupted, customers generally experience losses that are much greater than the cost of the electricity not delivered. While the cost of service determines the electric rates, the value of that service is different for each customer.

Estimates of typical annual values for the number of momentary outages and total time of extended outages can be found from utility bills and/or facility records. (Many organizations have a job ticket that tracks power loss recovery costs.) The direct cost impact of momentary outages on either a dollar-per-incident or dollars-per-minute basis is calculated. If the momentary outage results in an extended disruption at the facility, the direct cost impacts of extended outages on a dollar-per-minute or dollars-per-hour basis is calculated.

The cost value represents an annual direct operation cost that could be avoided with a properly configured CHP system. This is treated as operating savings in a CHP feasibility analysis. Dividing this total cost value by the number of unserved kilowatt-hours (average power demand in kilowatt times total annual outage time in hours) produces a value of service estimate similar to those included in Table 23-2.

Table 23-2 shows that even momentary outages result in extended disruptions to the normal routine of business. Thirty-minutes is used as an assumed recovery time; as would be the case where HVAC equipment needs to be manually reset after an outage, or personal computer workstations that need to undergo a hard reboot. The cost of an outage for the representative PG&E commercial customer is estimated at \$45,000 per

Facility Outage Impacts			Annual Outages		Annual Cost	
Power Quality Disruptions	Outage Duration per Occurrence	Facility Disruption per Occurrence	Occurrences per Year	Total Annual Facility Disruption	Outage Cost per Hour	Total Annual Costs
Momentary interruptions	5.3 seconds	0.5 hours	2.5	1.3 hours	\$45,000	\$56,250
Long duration interruptions	60 minutes	5.0 hours	0.5	2.5 hours	\$45,000	\$112,500
TOTAL			3	3.8		\$168,750
Unserved kWh per hour (based on a 1500-kW average demand)			1500 kWh			
Customer's estimated value of service (\$/unserved kWh)			\$30/unserved kWh			
Normalized annual outage costs (\$/kW-year)			\$113 \$/kW-year			

Note: This table is an example of how to quantify the cost of facility disruptions due to both momentary and long-term outages. The number of occurrences in this example is based on data obtained by EPRI from PG&E customers. The disruption caused by a particular type of outage is customer specific.

TABLE 23-2 Value of Service—Direct Cost Estimation and CHP Value¹²

hour of disruption based on operating history. Assuming an average plant power demand of 1500 kW, the value of service (VOS) is estimated to be \$30 per unserved kilowatthour; this is toward the lower range of outage costs for commercial customers.

Because outages occur infrequently, at different times, and have different durations, it is difficult to determine the annualized cost of outages. If a county emergency management agency “invests” in backup power generation facility in order to align itself with a statewide power security requirement, or to protect brand identity in economic development initiatives, this cost represents its willingness to pay (WTP) for power security.

Table 23-3 provides a constant-dollar comparison of the EPA’s hypothetical 1500-kW natural gas–fueled CHP system with and without the capability to provide backup power during a grid outage. The impact of enhanced reliability is calculated in two different ways:

1. *VOS.* For a customer with a VOS of \$30 per unserved kilowatthour and an expected decrease in downtime of 3.8 hours per year, the internal rate of return for the CHP project example increases from 12.2 percent for the standard CHP system to 17.5 percent for the system with backup capabilities. The net present value increases by a factor of four (\$1,239,507 divided by \$311,302).
2. *WTP.* For the customer with the WTP, a capital credit is taken for the 1500-kW backup gen-set, controls, and switchgear that would not be needed because backup capability is integrated into the CHP system. The EPA report takes care in acknowledging that some minimal amount of on-site generation is needed

CHP System Components	Standard CHP (No Backup)	Value of Service (VOS) CHP with Backup—Direct Cost with Steam Generator	Willingness to Pay (WTP) CHP with Backup—Avoided Cost of Diesel Generator
Generator capacity (kW)	1,500	1,500	1,500
CHP system installed cost (\$/kW)	1,800	1,800	1,800
Added controls & switchgear cost (\$/kW)	N/A	175	175
Typical backup gen-set, controls & switchgear (\$/kW)	N/A	Not valued directly	(550)
Total CHP system capital cost (\$/kW)	1,800	1,975	1,425
Total CHP system capital cost (\$)	2,700,000	2,962,500	2,137,500
Net annual energy savings (\$)	400,000	400,000	400,000
Decrease in annual outage time (hours/year)	0	3.8	Not valued directly
Customer value of service (\$/kW-year)	N/A	113	Not valued directly
Annual decrease in outage costs (\$)	N/A	168,750	Not valued directly
Total annual savings (\$)	400,000	568,750	400,000
Payback (years)	6.8	5.2	5.3
Internal rate of return (%)	12.20	17.50	16.90
Net present value (at 10% discount) (\$)	\$311,302	1,239,507	822,665

TABLE 23-3 CHP Value Comparison with and without Backup Power Capability¹²

for black start but that the incremental capital cost for this is more than offset by credit from the displaced backup gen-set. With the WTP method, the simple payback for the CHP system is reduced from 6.8 to 5.3 years and the internal rate of return is increased to 16.9 percent.

The IEEE Reliability Study

An example of a reliability study—keeping cost considerations constant—comes from IEEE/ANSI Standard 493 “Recommended Practice for the Design of Reliable Industrial and Commercial Power Systems.”

The Institute of Electrical and Electronic Engineers prepared a generic, but mathematically rigorous reliability study of an idealized radial power system that uses actual field records of component reliability data gathered by the U.S. Army Corps of Engineers Power Reliability Enhancement Program. Two radial systems are modeled:

1. The first with CHP run in parallel with a typical macrogrid utility (schematic shown in Fig. 23-3).
2. The second without CHP (schematic not shown, but with the same power chain architecture of Fig. 23-3 without the continuously operating 13.8-kV gas turbine).

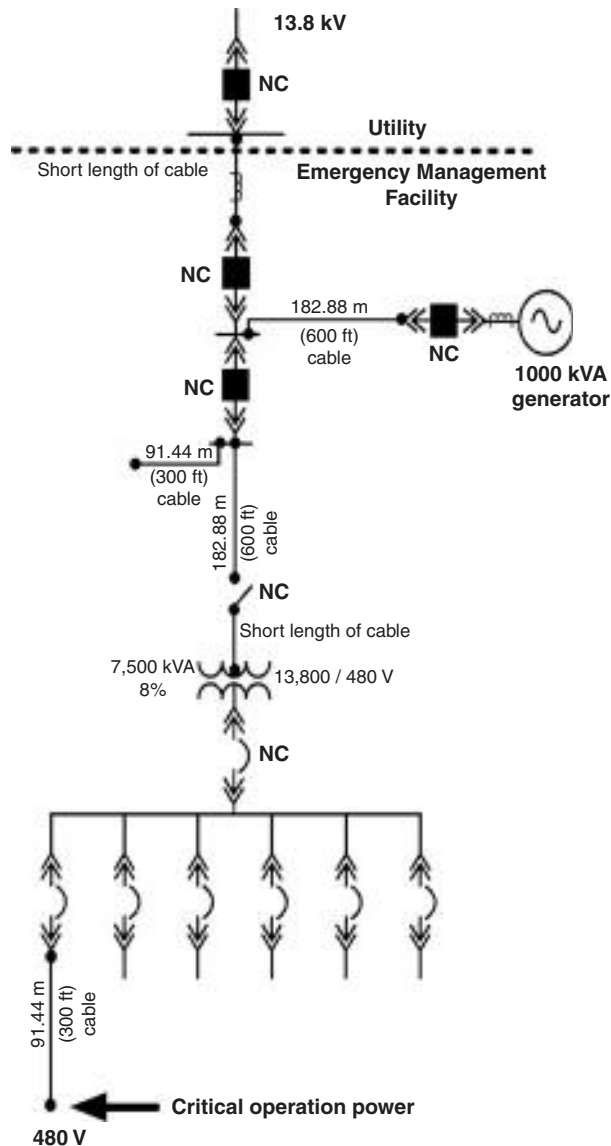


FIGURE 23-3 Simple radial power system with CHP. [Source: IEEE/ANSI 493-2007 (Ref. 13).]

The two radial systems assumed the same failure rate of 1.64 failures per year and the same average hours of downtime per failure of 2.58 hours. From this data, the availability of the utility was computed as 0.999705338.

Formal reliability studies apply field data on failure rates for every element of a power system. In this example, all the main elements along the power chain—from utility and normally paralleled 13.8 generator, down through the transformer, breakers, switches, and every foot of cable—has a computed reliability index. The power chain model is transferred into software that uses cut-set or Monte Carlo simulation methods to characterize operational availability.

When the reliability block diagram was built and the numbers run, the utility-only radial system yielded an average forced hours of downtime per year that was about twice as large as the radial system with cogeneration. The availability of both systems were about the same—0.999511730 versus 0.999801235—but the effect of transformer availability and a generating source at utilization voltage, could be clearly seen. The transformer is the most critical single point of failure in the IEEE system.

A more rigorous description of the reliability modeling process for critical operations power systems appears in Ref. 14.

Summary of Reliability Worth

The quantitative assessment methods shown in this chapter's calculations are idealized for representative generation technologies with CHP as the core concept. Other distributed resource technologies, such as fuel cells and batteries, are permitted as prime movers in Article 708, but beyond the scope of this chapter.

The type and extent of new or upgraded electrical systems must carefully balance the costs of service interruptions against the capital costs of backup systems. Each facility, nested within a macrogrid with unique operating characteristics, will require a separate sensitivity analysis of avoided costs that takes into account the scale and configuration of the entire emergency management facility real-time infrastructure.

Other considerations include

- Before any jurisdiction decides to build a CHP-based COPS all energy conservation measures should have already been deployed. Remove all inefficient equipment and occupant behaviors out of baseline energy consumption, first.
- The constant-dollar method enables an intuitive understanding of real cost trends but will tend to understate the carrying cost of capital and present investment alternates.
- A small cogenerator may need to meet nonattainment area requirements for NO_x under the so-called bubble concept. Planners should examine the emission level of the diesel engine before a CHP retrofit to assess conformity the larger, local carbon regime.
- Many existing small municipal power plants are idle because of high operating costs relative to the cost of grid-supplied power. These small plants could be retrofitted for CHP-based COP. Municipal utilities also have advantages in financing because they are tax exempted and so is the interest paid on their obligations.
- An existing legacy oil, coal, or diesel emergency power system could be retrofitted for cogeneration and still qualify for a federal energy tax credit as long as on-site energy use is reduced.

Regulation and Innovation

There are improvements in many headline distributed resource technologies; now vital system innovation is to drive familiar technologies like cogeneration to the tipping point. Given geopolitical conditions, energy and homeland security are not that far apart. The real challenges may not lie in the physics but in the politics. Standards like Article 708 can shape a new market niche for CHP.

Developing methods for the possibilities presented in this chapter will require us to look in many places for inspiration and tools. Other European countries, such as The Netherlands and Denmark have accelerating success with CHP.

As a final, specific, example consider the borough of Woking, a city of 90,000 in the south of England, (made famous as the city where Martians first landed in H. G. Wells science fiction classic, *War of the Worlds*) installed a CHP regime in 2006 that provides combined heat and power to civic offices, a local parking lot, two hotels, and leisure centers in its downtown development district. It features a 1000-kW, a 950-kW generator, a 200-kW fuel cell, and a number of photovoltaic cells. It is run by a private, for-profit energy service company.¹⁵

Why district heating has not caught on in the United States is a Rorschach test of perspective. The first commercial power plant in the United States (built by Edison in 1882) actually was a cogeneration plant. Some have lamented the absence of a single project “champion” like Edison at the local level; a profit-minded personality responsible for matching capital opportunities, for purchasing commercial energy inputs, grid power, generating equipment, and local opportunity fuels. Others blame the “BANANA” syndrome in which developers are met with community resistance that insists: “build absolutely nothing anywhere near anyone.”

If we are serious about power security, we should not waste this moment. We should work the generation and delivery mix from both ends: CHP up to the grid, and from the grid down to CHP. The ultimate destination should be a stable point somewhere the thermal and electric macro- and microgrids synergistically support each other.

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CHAPTER 24

Case Study 6: Eco-Footprint of On-Site CHP versus EPGS Systems*

Milton Meckler

Lucas B. Hyman

Kyle Landis

This chapter compares the eco-footprint of three sustainable on-site CHP system alternatives with a representative 30 percent thermally efficient conventionally designed remote electric utility/merchant power generation station (EPGS) serving a 3.5-MW gas turbine installation proposed for a central California university campus.

It has been demonstrated (2007 ASHRAE Transactions # DA-07-009) that sustainable on-site combined heat and power (CHP) systems for large multibuilding projects employing a simplified design approach from that of a conventionally designed miniutility-type CHP systems employing large volume/footprint, costly, high thermal mass heat recovery steamgenerators (HRSGs), and 24/7 stationary engineers, can result in lower annual owning and operating costs.

The above peer-reviewed 2007 paper illustrated the use of prefabricated, skid-mounted hybrid steam generators with internal headers, fully integrated with a low-pressure drop heat extraction coil (in lieu of an HRSG) located in the combustion gas turbine (CGT) exhaust. Subject CGT extraction coil utilized environmentally benign heat transfer fluid to redistribute extracted CGT exhaust waste to serve campus multibuilding annual space cooling, heating, and domestic hot water loads with system thermal balance facilitated via maintenance of a high year-round log mean temperature differential at the CGT extraction coil, also resulting in a lower CGT backpressure, and significant life-cycle-cost (LCC) savings. This chapter also takes an alternative look at the earlier referred CHP plant

*This case study is reprinted with permission from ASME, and originally appeared as ASME paper ES2008-54241 presented at the ASME International Conference on Energy Sustainability, August 2008.

designs for greater operating economies along with a third CHP alternative employing a direct CGT exhaust gas-fired two-stage absorption chiller, and then compare the eco-footprint and life-cycle cost for each of the three CHP options with the previously referenced EPGS supplying comparable annual electric power requirements.

Finally, using the eco-footprint of the EPGS as a baseline, the most promising CHP alternative of the above three will also be explored as a potential “cap and trade” candidate to further reduce its first cost and therefore enhance its sustainability from both an energy and greenhouse gas emissions standpoint.

Introduction

What does one mean by the term “sustainability,” and is it different from building sustainability or combined heat and power (CHP) sustainability? Ray Anderson, chairman of Interface Inc. was quoted as stating “sustainability implies allowing a generation to meet its needs without depriving future generations of a way to meet theirs.” The board of directors of the American Society of Heating, Refrigerating, and Air-Conditioning Engineers (ASHRAE) approved the position document “Building Sustainability” on June 23, 2002, which stated, “ASHRAE supports building sustainability as a means to provide a safe, healthy, comfortable indoor environment while simultaneously limiting the impact on the Earth’s natural resources.”

A subtle additional component for CHP sustainability is implied in Mr. Anderson’s use of the words “allowing a generation to meet its needs.” The latter recognizes the mechanical, electrical, plumbing (MEP) consultant’s real-world need to justify (or sustain) value-added CHP benefits for its clients. What better way to attract funding for CHP than to utilize LCC methods to select among traditional versus more attractive CHP alternatives to secure client commitment and thereby advance overall green project sustainability?

Other factors in addition to LCC analysis include waste heat versus prime energy utilization, building operator skill sets, reliability, local utilities real-time costs, related environmental concerns, for example, greenhouse gas emissions, eco-footprint, and green marketing benefits to refocus initial client goals when setting long-term budgetary, building design, and operational parameters. This is particularly true when considering whether to employ on-site cooling CHP systems that rely in part or exclusively on available local gas and electric utilities to serve their new or renovated, large-scale, tenant-occupied or leased building facilities. And when doing so, one must realistically ask: how foreseeable are future energy costs likely to be, present world conditions being what they are?

Among the many chiller technologies available in the market today, single- and two-stage lithium bromide (LiBr)–water absorption chillers have proven to be the most cost-efficient topping-cycle options or hot water for converting available high-temperature waste heat, for example, 350 to 400°F (177 to 204°C), into chilled water cooling. On the bottoming-cycle end of available cascading lower-temperature waste heat (e.g., 200 to 250°F or 93 to 121°C), ammonia-water absorption chillers to produce ice for thermal energy storage (TES) and desiccant regeneration for dehumidification equipment (e.g., outdoor air pre-conditioners) are employed.

Although the previously referenced indirect fired two-stage and single-stage LiBr–water absorption chillers utilize steam or hot water for activation, they can also employ waste heat directly to generate chilled water. In fact, efforts to supply turbine exhaust

directly to a modified two-stage direct gas-fired LiBr-water absorption chiller configuration have already been demonstrated (Berry et al. 2004 and 2005; Meckler and Hyman 2005; Pathakji et al. 2005).

Achieving the earlier described synergies within on-site CHP systems, however, requires thinking “out of the proverbial box” to identify similar converging opportunities by enhancing gas turbine engine performance at lower prime energy and overall capital cost. Close-coupled turbine inlet cooling, supplied from two- and/or single-stage steam (or hot water) absorption chillers, benefits enhanced turbine power performance.

Description of Compared Systems

Three comparative cogeneration systems were developed to partially meet the electric, cooling, and heating requirements of a central California university campus. Refer to Table 24-1 for a breakdown of campus loads; namely, electric (kW), cooling (tons), and heating loads (MMBtuh) listed with peak, minimum, and average values. The systems are identical in terms of turbine configuration but differ in the manner in which exhaust heat is extracted and utilized. One alternative uses a conventional cogeneration arrangement with a heat recovery steam generator (HRSG), while the other alternative uses the integrated CHP gas cooling system (ICHP/GCS) approach. Refer to Fig. 24-1 for a schematic of the conventional CHP plant; Fig. 24-2 for a schematic of the ICHP/GCS plant; and Fig. 24-3 for the third alternative considered—a direct turbine exhaust-fired two-stage LiBr-water absorption chiller to produce both heating and cooling. All three CHP plants were sized to meet the average base electric load of the campus (approximately 3.5 MW). However, the 3.5-MW combustion gas turbine (CGT) will turn down minimally on weekends and other periods of relatively low campus occupancy to match the electric demand. Exporting energy to the serving utility was found to be uneconomical, since the cost to produce the electricity is typically greater than the amount that the utility pays for exported electricity. Electric, cooling, and heating loads used in the analysis are based on actual campus data and averaged into four seasonal 24-hour profiles. The CGT utilized in all the alternatives has fuel consumption (at 3.5 MW electric output) of 42.7×106 Btu/h (12.5×106 W). The boilers utilized in the alternatives are assumed to have an efficiency of 80 percent, and the electric chillers utilized in each alternative are assumed to have an efficiency of 0.6 kW/ton (COP = 5.9).

Conventional CHP Plant

The conventional CHP plant, as shown below in Fig. 24-1 uses an HRSG to produce high-pressure steam (HPS), which is used to drive a two-stage absorption chiller with an assumed steam consumption of 9 lb/ton (1.2 kg/kW) before being reduced to low-pressure

	Electric (kW)	Cooling (tons)	Heating (MMBtuh)
Peak	12,831	1875	70.6
Minimum	3,725	206	6.8
Average	6,156	714	28.8

TABLE 24-1 Campus Electric, Cooling, and Heating Loads

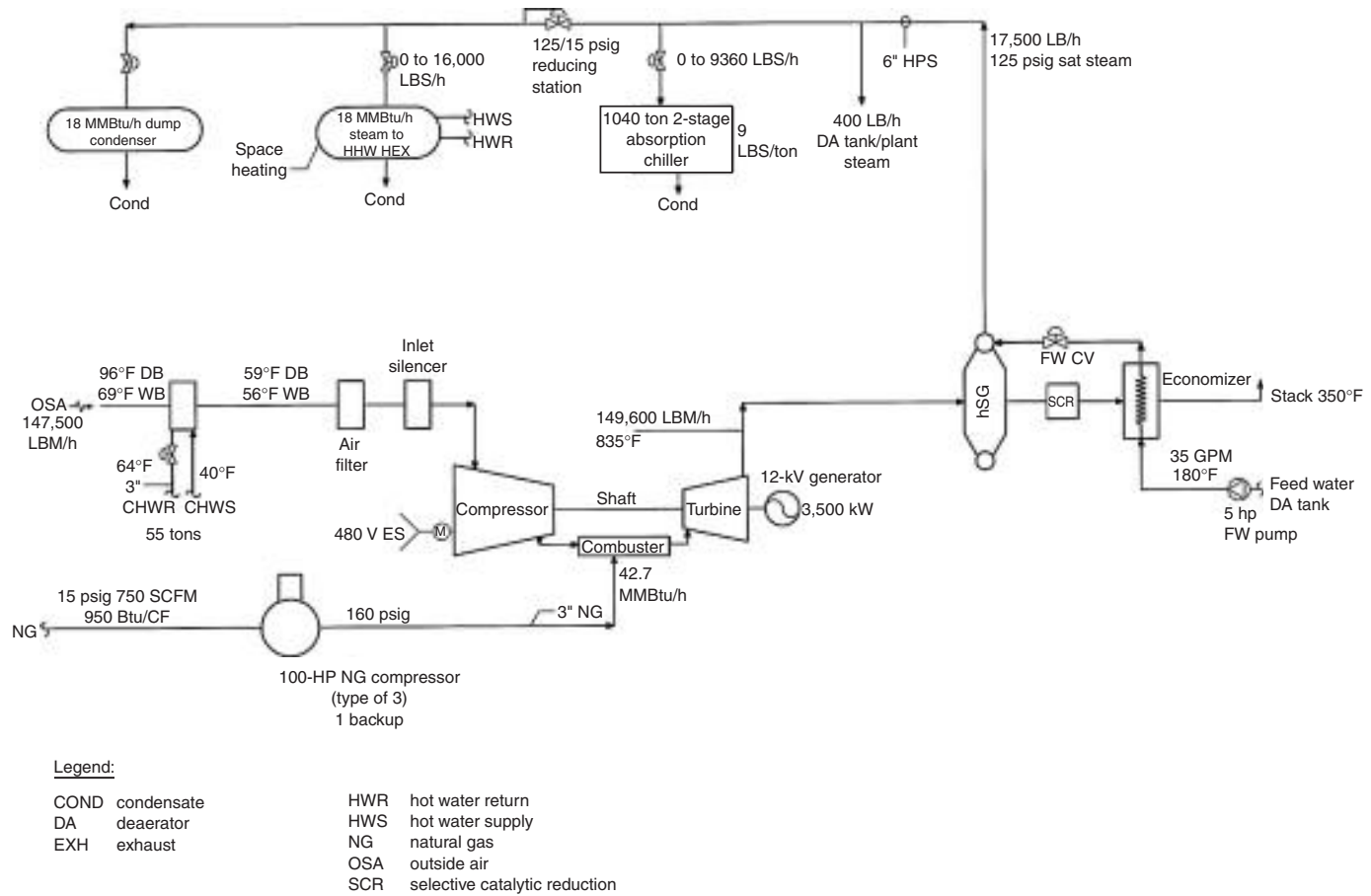


FIGURE 24-1 Conventional CHP plant.

steam (LPS). The LPS is then used to make heating hot water (HHW) for distribution to the campus. Any energy not utilized by the plant is rejected to a dump condenser to be rejected to atmosphere by either a cooling tower or radiator. The balance of heating and cooling loads that are not served by the cogeneration plant are served with gas-fired boilers and electric driven-centrifugal chillers.

ICHP/CGS Plant

The inherently self-regulating ICHP/GCS, as shown in Fig. 24-2, met the nominal 1040-ton (3658-kW) cooling requirement of our 3.5-MW campus project by employing more efficient, commercially available low-mass hybrid steam generators and utilizing a commercially available, nominal 1040-ton (3658-kW) adapted two-stage high-temperature heat transfer fluid (HTHTF) heated absorption chiller with an assumed heat rate of 10,600 Btu/h/ton (COP = 1.13). The ICHP/GCS plant can be functionally integrated with controls, plate-and-frame heat exchangers, turbine inlet cooling coil, pumps, interconnecting piping, and CGT waste heat extraction coil and prefabricated (for minimal on-site erection) water type absorption chiller. The ICHP/GCS plant uses an exhaust-to-HTHTF heat exchanger (HEX) to recover the exhaust heat by heating the HTHTF from approximately 250°F to as high as 600°F (316°C). The HTHTF can first supply a hybrid HEX to produce LPS. The LPS can be used to drive a single-stage absorption chiller.

The HTHTF is then used to drive a two-stage absorption chiller followed by a plate-and-frame HEX to produce HHW. Note that domestic hot water (DHW) can also be produced to further utilize the recovered heat. However, in the specific case analyzed here, the majority of recovered heat was utilized for campus heating and cooling demands, and dumping of recovered heat was minimal. The thermal utilization is arranged in this order due to the heat temperature and quality requirements of the various system components. For example, the two-stage absorption chiller has a maximum HTHTF inlet temperature of 425°F (218°C). Therefore, some of the recovered heat may need to be utilized prior to the two-stage absorption chiller depending on the HTHTF supply temperature. Though the most efficient way to use heat would be to produce HHW prior to the two-stage absorption chiller, the coincident campus cooling and heating loads are not such that the HHW HEX would always reduce the HTHTF below 425°F (218°C). Since the HHW HEX requires lower-temperature HTHTF than the two-stage absorption chiller, the HEX was placed downstream of the chiller. Like the conventional plant, the balance of heating and cooling loads that are not served by the cogeneration plant are served with gas-fired boilers and electric-driven centrifugal chillers.

Direct Turbine Exhaust-Fired Two-Stage LiBr-Water Chiller Plant

This direct turbine exhaust-fired two-stage LiBr-water chiller plant, as shown in Fig. 24-3, includes an absorption chiller capable of producing both chilled and hot water, which is directly coupled to the CGT exhaust stream. The subject absorption chiller can produce 1740 tons of cooling (at 0 percent heating) and approximately 17×10^6 Btu/h of heating (at 0 percent cooling). It incorporates an integral heat recovery chiller therefore an HRSG is not required. Note that the cooling load must be at least 30 percent of the heating load in order to allow simultaneous heating and cooling. Therefore, it was assumed that whenever the cooling load was below 30 percent, the absorption chiller would operate in heating mode.

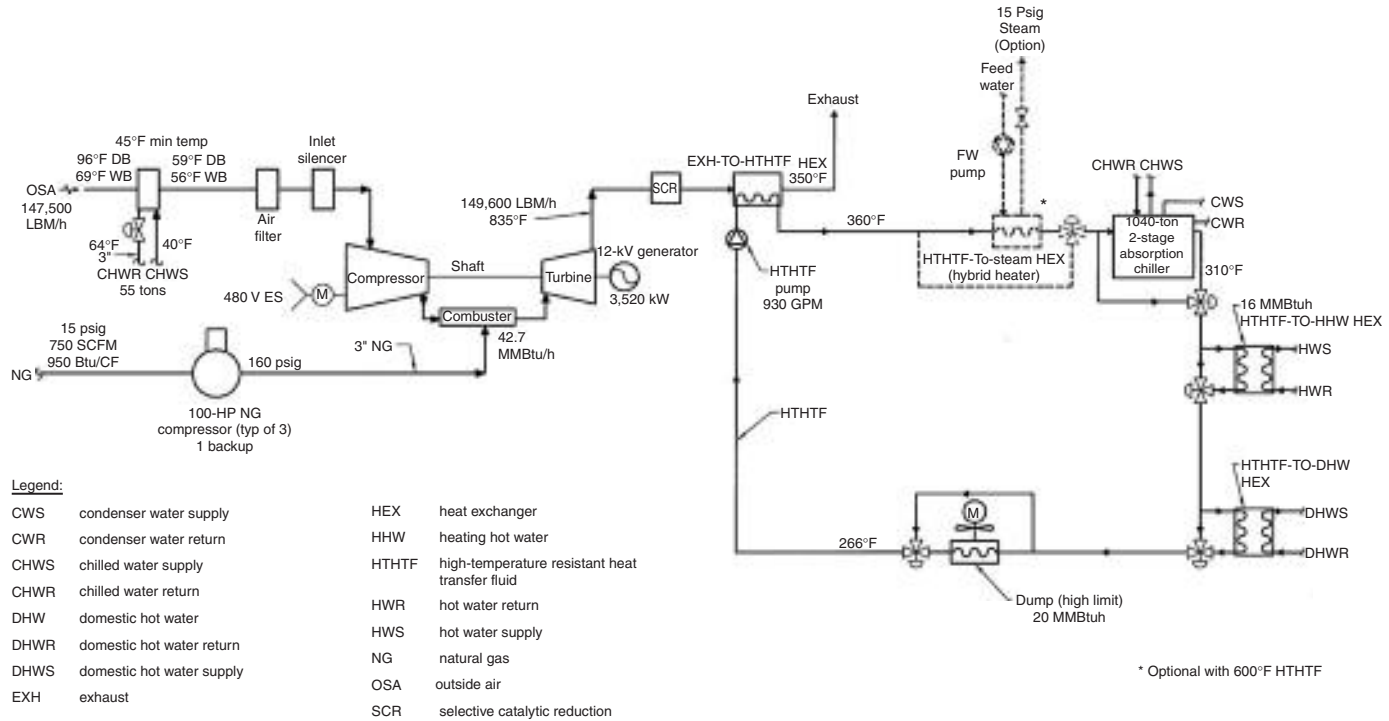
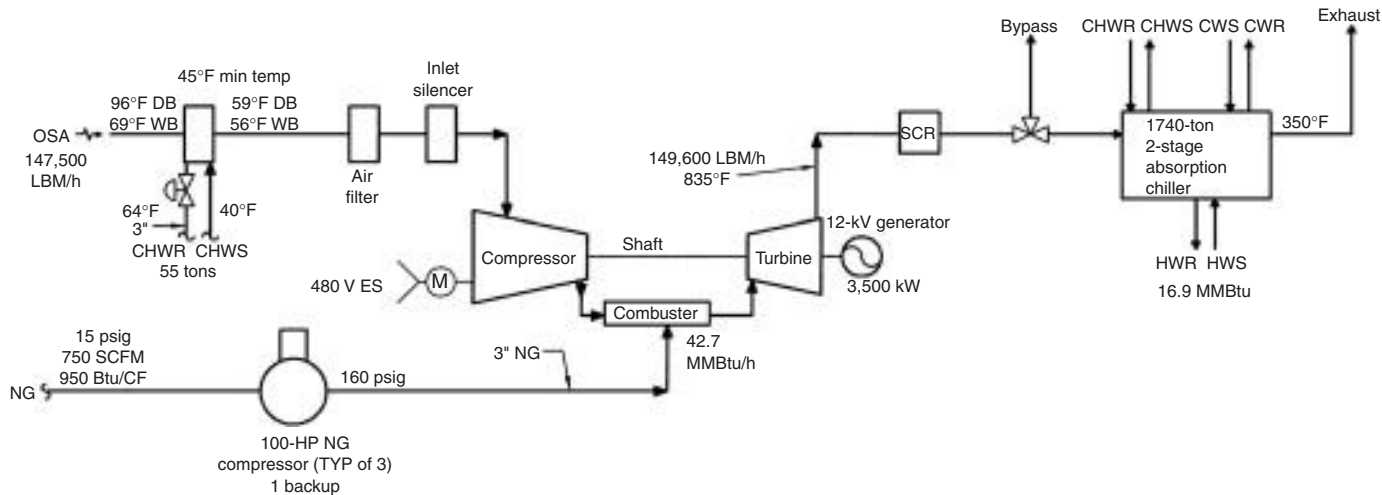


FIGURE 24-2 ICHP/CGS plant schematic.



Legend:

CWS	condenser water supply	HEX	heat exchanger
CWR	condenser water return	HHW	heating hot water
CHWS	chilled water supply	HTHTF	high-temperature resistant heat transfer fluid
CHWR	chilled water return	HWR	hot water return
DHW	domestic hot water	HWS	hot water supply
DHWR	domestic hot water return	NG	natural gas
DHWS	domestic hot water supply	OSA	outside air
EXH	exhaust	SCR	selective catalytic reduction

FIGURE 24-3 Direct turbine exhaust-fired two-stage LiBr chiller plant.

System Cost Comparison

Capital Cost Comparison

Tables 24-2 through 24-4 show the approximate differential material cost for major equipment. Equipment that is the same for either plant is not included in the estimate. As shown, the cost for major equipment for the conventional plant is approximately \$150,000 higher than for the ICHP/GCS plant. Additionally the cost of the direct turbine exhaust plant is \$560,000 higher than for the ICHP/GCS plant.

Energy Cost Comparison

An energy model was prepared to calculate the energy usage and cost differences between the plants. Table 24-5 provides the annual natural gas, electricity, and combined total energy cost for each of the mentioned three alternates. As shown, the ICHP/CGS plant

HRSG	\$360,000
1040-ton two-stage absorption chiller	\$500,000
900-ton electric chiller	\$450,000
16-MMBtu/h steam-to-HW HEX	\$80,000
18-MMBtu/h dump condenser	\$90,000
Miscellaneous	\$100,000
Total	\$1,580,000

TABLE 24-2 Conventional Cogeneration Plant Capital Costs

IHT HEX	\$240,000
1040-ton two-stage absorption chiller	\$600,000
900-ton electric chiller	\$450,000
16-MMBtu/h HTHTF-to-HHW HEX	\$90,000
Miscellaneous	\$50,000
Total	\$1,430,000

TABLE 24-3 ICHP/CGS Cogeneration Plant Capital Costs

1682-ton two-stage absorption chiller	\$1,690,000
500-ton electric chiller	\$250,000
Miscellaneous	\$50,000
Total	\$1,990,000

TABLE 24-4 Direct Turbine Exhaust Plant Capital Costs

	Conventional Plant	ICHP/CGS Plant	Direct Exhaust Plant
Natural gas cost (\$)	4,635,000	4,578,000	5,028,000
Electricity cost (\$)	2,826,000	2,814,000	2,802,000
Total energy cost (\$)	7,461,000	7,392,000	7,830,000

TABLE 24-5 Estimated Energy Cost Summary

Conventional Cogeneration Plant	
17500 lb/h HP/LP steam system	\$5,000
Operator cost (FT operator)	\$480,000
Total	\$485,000
ICHP/CGS and Direct Exhaust Plants	
Operator cost (FT operator)	\$80,000
Total	\$80,000

TABLE 24-6 Estimated Differential Operation and Maintenance Costs

offers estimated energy cost savings of approximately \$70,000 per year over the conventional plant, and approximately \$440,000 over the direct exhaust plant. The additional cost of the direct exhaust plant is due primarily to increased reliance on a natural gas-fired boiler to meet the heating demand. This is due to losses in producing hot water in the turbine exhaust-fired two-stage LiBr-water chiller (1.18 MBtu/h in to 1.00 MBtu/h out).

Operation and Maintenance Cost Comparison

Table 24-6 summarizes the differential cost in both personnel and maintenance cost. The significant cost difference between either the ICHP/GCS and direct turbine gas-fired absorber plants is related to the need for 24/7 stationary engineers for the conventional CHP alternate use of high-pressure (exceeding 15 psig) steam with HPS code mandating six full-time 24/7 operators (comprising 168 hours vs. one operator requiring 40 hours per week for monitoring and routine maintenance). The assumed full-time operator cost is \$80,000 each per year. The \$80,000 per year assumed cost is fully burdened, and includes salary, payroll taxes, Social Security, Medicare, health care, and retirement. The annual operation and maintenance costs of the conventional plant are \$400,000 more than the ICHP/GCS plant and direct turbine exhaust plant.

20-Year Life-Cycle Cost

Based on the above capital, energy, and maintenance costs, 20-year life-cycle-cost (LCC) comparisons were prepared. LCC analysis is a process by which system costs are calculated, not just for a particular period, but for the life of the system. In addition, LCC analysis is a process by which the time value of money is taken into consideration. The LCC analysis prepared assumes a discount rate of 6 percent, an operation and maintenance escalation rate of 3 percent, and an energy escalation rate of 2 percent. The

Case	Life-Cycle Cost (\$)	Life-Cycle-Cost Savings (\$)
Conventional cogeneration plant	108,738,000	
Hot oil cogeneration plant	101,752,000	6,986,000
Direct exhaust cogeneration plant	108,189,063	548,937

TABLE 24-7 Life-Cycle-Cost Summary

discount rate equates future values with present values. That is, the discount rate is the number used to determine the equivalent present dollar value given some future dollar value. In general, the discount factor should equal approximately the long-term cost of money. Table 24-7 summarizes the LCC comparison and shows the estimated LCC savings of the ICH/CGS plant over the conventional plant are almost \$7 million dollars.

Fuel Related Environmental Issues Impact Alternate Eco-Footprints

Environmental perspectives are unbalanced when comparing the cost of electricity and natural gas delivered to building utility meter. Recalling that natural gas–fired electric utility plants operate around 35 percent average annual efficiency (or fuel energy utilization) and CHP plants operate between 50 and 85 percent fuel energy utilization (dependent on waste heat usage—total utilization as well as heating vs. cooling), it is essential to compare their environmental impacts on a fuel source basis and not a delivered to on-site metered cost basis. Also, the relative annual average cost of natural gas on a dollar-per-unit volume or electricity on a dollar-per-kilowatthour delivered basis to any U.S. location is inherently site specific and will vary depending upon applicable rate structures. When considering sustainability from an environmental standpoint, one must first estimate the energy content of fuel delivered to the serving electric utility for each purchased kilowatt-hour delivered versus the energy content for each 1000 ft³ (28.3 m³) of natural gas delivered on a comparable source energy basis adjusted for transmission losses.

Table 24-8 shows that the CHP systems analyzed reduced CO₂ emissions by as much as 20 percent. Table 24-9 shows that the CHP systems analyzed reduced NO_x emissions by as much as 37 percent. These values were calculated using data from the United

	Conventional CHP	ICHP/GCS CHP	Direct Exhaust CHP
National Average			
Annual CO ₂ reduction (lb)	24,906,212	25,849,270	17,457,586
Annual CO ₂ reduction (%)	19	20	14
Northeast Average			
Annual CO ₂ reduction (lb)	8,175,425	9,068,328	824,391
Annual CO ₂ reduction (%)	8	9	1
Western Average			
Annual CO ₂ reduction (lb)	15,492,846	16,407,685	8,099,129
Annual CO ₂ reduction (%)	14	14	7

TABLE 24-8 CHP versus EPGS CO₂ Reduction

	Conventional CHP	ICHP/GCS CHP	Direct Exhaust CHP
National Average			
Annual NO _x reduction (lb)	60,473	61,408	53,906
Annual NO _x reduction (%)	37	37	33
Northeast Average			
Annual NO _x reduction (lb)	20,614	21,428	14,279
Annual NO _x reduction (%)	20	21	14
Western Average			
Annual NO _x reduction (lb)	42,787	43,668	36,322
Annual NO _x reduction (%)	31	32	27

TABLE 24-9 CHP versus EPGS NO_x Reduction

States Environmental Agency's eGRID2006, which provide power plant emissions data for the year 2004. Since generation technologies, fuel types, and age of plants varies widely between regions, the calculations include a comparison using data from the western United States, northeastern United States, and the national average.

Summary and Conclusions

ICHP/GCS systems are easier to operate and are inherently more user-friendly and responsive to the highly variable occupancy cooling and heating thermal loads than traditional miniutility CHP plants employing downsized HRSGs. One major benefit was the elimination of the code requirement for 24/7 stationary engineers necessary in the conventional CHP base case (note that one full-time 40-hour-per-week operator was still assumed in the ICHP/GCS case). The ICHP/GCS schematically illustrated in Fig. 24-2 lends itself to the use of smaller-footprint, prefabricated, vertical hybrid steam generators. These can be mounted on modular skids complete with piping and controls for rapid on-site interconnection with similar functionally integrated equipment, for example, heat exchangers and pumps that are prepped on modular skids with points of connection identified for ease of on-site interconnection prior to charging with HTHTF. In addition to life-cycle costs and operation considerations, ICHP/GCS systems have the potential to reduce the environmental impact in comparison to the other CHP systems, and significantly so in comparison with traditional connection to the EPGS.

Claimed advantages of the ICHP/GCS include smaller thermal mass of hybrid steam generator permitting quick response to varying building HVAC&R loads, and elimination of the need for 24/7 stationary engineers due to the low-pressure operation of the HTHTF recirculation loop. Additionally, the reduced CGT exhaust extraction coil pressure drop improves CGT power performance. The above analysis demonstrates that the ICHP/GCS system has a lower overall life-cycle cost. Also, the ICHP/GCS system allows for reduced installation time, operation complexity, CHP system downtime, and overall footprint.

ASHRAE's policy statement on global warming in effect acknowledges that greenhouse gases are linked to global warming and must now be taken seriously by its members. ASHRAE's MEP members responsible for engineered building facilities lasting 20 to 30 years on average can minimize such global warming impacts by

advocating sustainability through cost-effective CHP today. ASHRAE building sustainability goals are likely to be significantly advanced through efficient and value-based on-site CHP systems differentiated using LCC and eco-footprint methods.

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CHAPTER 25

Case Study 7: Integrate CHP to Improve Overall Corn Ethanol Economics*

Milton Meckler

Son H. Ho

Abstract

This chapter presents a practical solution to improve the current overall corn ethanol economics. It is our intent in this chapter also to focus our attention on extraction of DDGS and corn ethanol employing the dry milling process since it appears to offer the greatest opportunity for substantial improvement. Alternate corn ethanol wet mill processing for the extraction of gluten protein meal for livestock food is also briefly described.

A hybrid integrated steam jet refrigeration/freeze concentration system (ISJR/FCS)¹ is proposed for the extraction of corn ethanol and distillers dry grain with solubles (DDGS) in dry milling process. Technical feasibility of substantially reducing corn ethanol first cost on a life-cycle basis as well as current operational costs and greenhouse gas emissions is demonstrated employing an actual case study.

Introduction

DDGS stands for distillers dry grains (DDG) with solubles (S) which comprise the principal coproduct obtained by condensing and drying the stillage remaining after the

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removal of ethyl alcohol (or ethanol) from the yeast fermentation of corn representing the major grain now used in the rapidly expanding manufacture of ethanol for blending with gasoline to reduce our nation's U.S. reliance on expensive imported crude oil and limited refining capacity to meet foreseeable U.S. energy needs.

In 2003, approximately 3.8 million tons of DDG were produced in domestic dry grind ethanol production. Ethanol has become a significant market for U.S. corn, consuming more than 1.8 billion bushels in 2006 to produce 4.8 billion gallons of renewable fuel according to the National Corn Growers Association (NCGA). DDGS production results from the separation of coarse fibrous DDG material from the mother liquor S' and finely suspended portion by centrifuge equipment. The remaining liquid or S' fraction is next concentrated by evaporation to a syrup or S which is then combined with the coarse DDG fibrous fraction to produce DDGS which is dried in heated air dryers prior to packaging for sale as a replacement livestock feed for beef and dairy cattle, swine, and poultry.

The use of proposed ISJR/FCS can eliminate the need for the mentioned costly direct gas-fired evaporator apparatus (for concentrating S') by arranging for S' to be fed directly into the ISJR/FCS to concentrate S' by freeze concentration resulting in water exiting as a "product" and S concentrate exiting separately as a "coproduct" followed by combining with DDG to produce DDGS.

We plan to demonstrate that it is technically feasible to substantially reduce corn ethanol first cost on a life-cycle basis as well as current operational costs and greenhouse gas (GHG) emissions employing an actual case study.²⁻⁵ Subject case study findings will show that utilizing a heat recovery steam generator (HRSG)⁶⁻⁸ supplied with turbine discharge exhaust from a 3.5-MW on-site combustion gas turbine (CGT) cogeneration (combined heat and power, or CHP) to produce high-pressure steam^{9,10} to interface with ISJR/FCS within the corn ethanol dry milling process can result in substantially lower ethanol production annual first and operating costs and substantially reduced associated GHG emissions.

Recent advances in biotechnology and improved corn crop practices now permit growers to harvest more corn without a substantial increase in acreage. They operate to mitigate earlier concerns that using corn to make fuel will divert corn and/or increase its cost for both human and livestock food markets.

Increasing corn ethanol production rates also results in increased DDGS supplies thereby reducing demand for corn use as a livestock feed while increasing the availability of nonethanol corn use for human food at lower market cost. In spite of drought conditions in parts of the Corn Belt in 2006, the average yield per acre was approximately 149 bushels corresponding to the second highest corn yield on record. Based on a 15-year trend line prepared by the NCGA, average yields are expected to reach 173 bushels per acre by 2015. Accordingly, DDGS yields and related processing cost have become a significant factor in overall corn ethanol economics.

With the rapid expansion of corn ethanol plants for fuel there are still some issues that cause reasonable concerns. While many farmers in the Midwest may think of ethanol as the "holy grail" of energy policy and the answer to their prayers, we must continually reevaluate our production methods to determine the most cost-effective and environmentally benign way to produce it. Done correctly ethanol could help deliver the United States from its current overdependence on foreign oil while reducing the related production emissions (GHG) that contribute to climate change. Expanding ethanol production hastily without a thorough, periodic assessment of process economics could, in

time, negatively impact current petroleum displacement goals while increasing GHG. The purpose in documenting our findings which follow is to conduct such an assessment particularly in the light of ongoing challenges questioning the economic and technical viability of present production methods to meet our stated public policy energy goals.

As part of the Energy Security and Independence Act of 2007, Congress authorized a fivefold increase in ethanol production by 2022. Less than half that amount would come from corn ethanol, which has been the principal market source for years and continues to grow in relation to the escalating cost and questionable sustainability of high cost imported crude.

The remaining feed source is expected to come from other available biofuel feed stocks, for example, switch grass, small trees, and other plants. Yet the latter proposed alternate biofuel feed stocks are still quite far from commercial-scale production. Fortunately the 2007 energy bill called for several environmental safeguards. The most important of which is a requirement that regardless of feed source, ethanol must achieve a 20 percent reduction in GHG as compared with conventional gasoline on a gallon-per-mile basis.

The job of calculating and monitoring GHG from various ethanol sources was given by Congress to the Environmental Protection Agency (EPA). Those calculations would accordingly have to account for both direct emissions, for example, associated with growing, harvesting, and refining corn and other biofuel feedstocks along with indirect emissions, for example, associated with changes in land use, as acres devoted to producing food are converted to producing fuel. Additionally a proper accounting would include not only the carbon absorbed by the corn grown to produce ethanol but the carbon released into the atmosphere when soil is prepared for planting additional corn, for example.

Yet there is no requirement for EPA to calculate the following:

1. The differential GHG and annual operating cost associated with use of natural gas and other fossil fuel alternatives in producing ethanol versus the use of available waste heat.
2. Take appropriate credit for coproducts produced with corn ethanol, for example, DDGS, which provide a high energy, high protein, food supplement thereby reducing demand for corn use as a livestock feed while increasing the availability of nonethanol corn use for human consumption at lower market cost.
3. The cost benefit of reclaimed DDGS feed with approximately 120 percent of the energy value of ground corn is rich in cereal and residual proteins, energy, minerals, B-vitamins, and growth factors plays a vital role in improving corn ethanol economics as will be seen.
4. Increased GHG emissions are associated electricity produced at a remote utility / merchant electric power generation station (EPGS) versus a functionally integrated on-site CHP plant generated electricity produced operating at a 75 to 85 percent annual fuel utilization with available waste heat for all corn ethanol dry and wet mill production needs.

These objectives will be addressed in some detail since they are believed to be essential for a more balanced evaluation of the likely environmental consequences when comparing and deciding among commercially available biofuels which ethanol feedstocks and processing methods offer the most economic benefit with the least adverse environmental societal consequences.

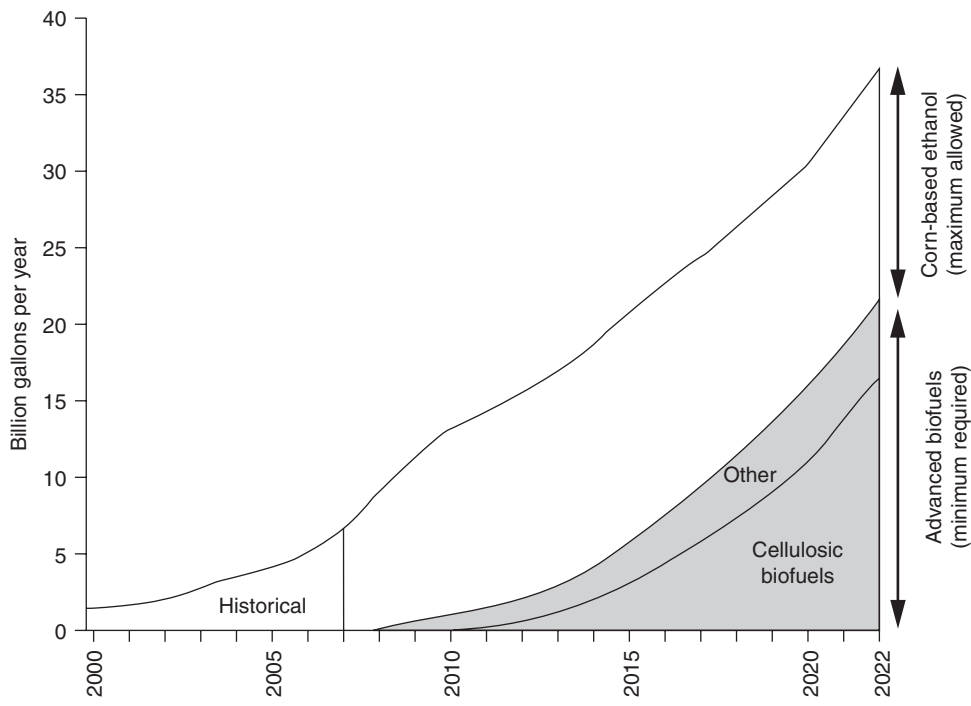


FIGURE 25-1 U.S. biofuel needs: 2000 through 2022.¹¹

Environmental Sustainability of Biofuels

The Energy Security and Independence Act of 2007 mandated 36 billion gallons of renewable fuels in the U.S. market by 2022. Figure 25-1 illustrates a published Cambridge Energy Research Associates Inc. (CERA)¹¹ projection of the relative quantities from both a historical and required capacities basis, respectively, by corn-based ethanol and advanced (cellulosic and other) U.S. biofuels by year envisioned by the new Energy Act of 2007. Clearly the major player today is believed to be corn ethanol provided the assumption that its life-cycle GHG emissions remain at least 50 percent less than gasoline's life-cycle emissions over the same time period. Therefore, if the U.S. is to achieve these goals, ethanol derived from cornstarch now representing over 40 percent of world biofuel production needs to make a significant impact in the petroleum-based transportation fuels market as shown in Fig. 25-1.

Current Corn Ethanol Processing

Corn ethanol is currently produced employing two general processing methods termed *dry milling* and *wet milling*. Wet mills, schematically illustrated in Fig. 25-2, process large amounts of corn and are generally built to process approximately 100 million or more gallons per year of ethanol. The wet milling process is designed to separate corn into a number of useful products including gluten feed and gluten meal used as animal feed components, the ethanol is concentrated to 95 percent azeotropic alcohol by distillation and after the removal of azeotropic water, the resulting fuel-grade alcohol product;

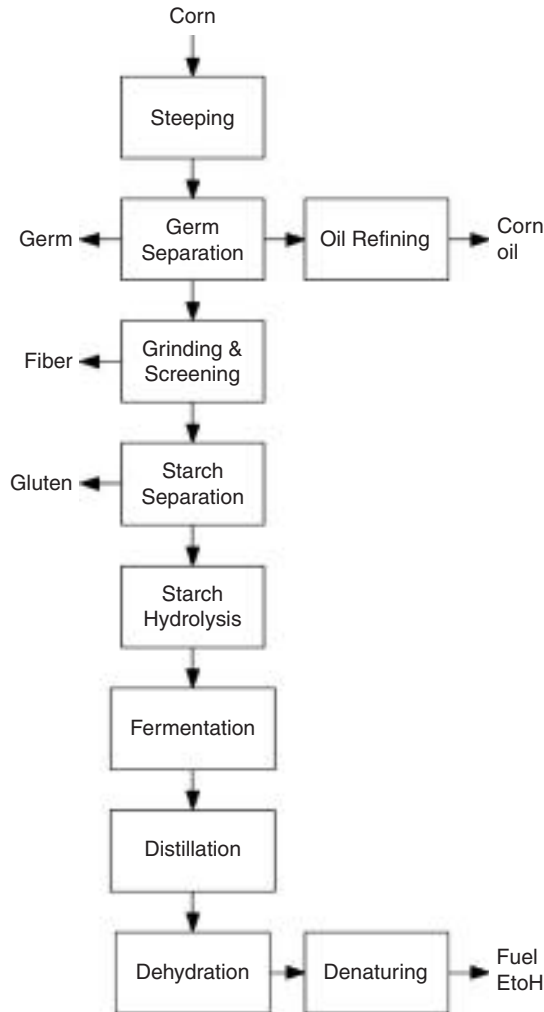


FIGURE 25-2 Corn wet milling process.

which contain fusel oils produced in the fermentation step, is denatured with 5 percent gasoline prior to shipping.

Dry mills, shown schematically in Fig. 25-3, are somewhat smaller in scale; producing on the order of 30 to 50 million gallons per year of ethanol; also produce large quantities of DDGS, a valuable coproduct made starting from the mash preparation obtained from the base of the distillation tower, in the manner illustrated in Fig. 25-3, which is used to produce the 190 percent azeotropic alcohol and which after the removal of azeotropic water, the resulting fuel-grade alcohol is also denatured with 5 percent gasoline prior to shipping.

Measuring capital energy or the energy associated with the manufacture of equipment associated with the production of corn and ethanol is difficult when comparing current production practices employing EPGS furnished electricity and natural gas— or other fossil fuel-fired distillation and evaporation equipment with the proposed on-site CHP generated electricity employing CTG turbine exhaust-driven steam-powered

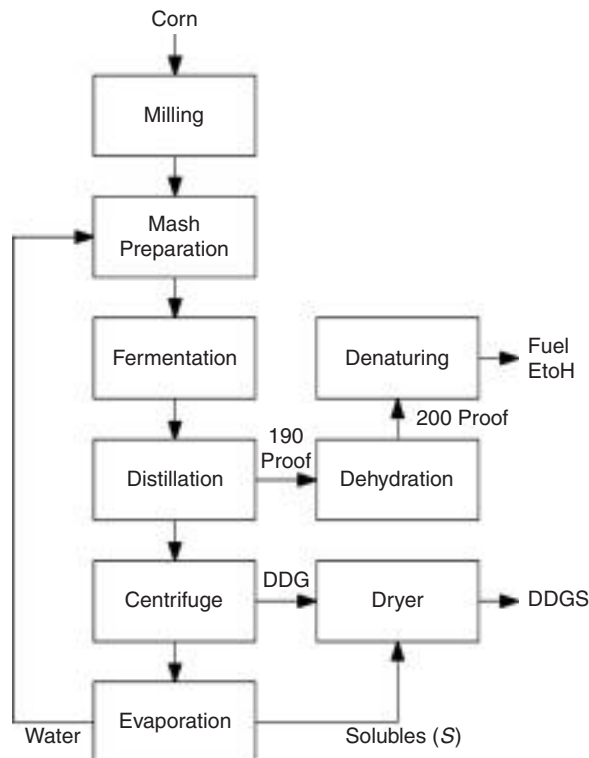


FIGURE 25-3 Corn dry milling process.

ISJR/FCS; lithium bromide (LiBr) vapor recompression absorber (VRA), the LiBr generator and distillation units for reducing the production costs for existing retrofitted and annual owning and production costs of new ethanol dry mill processing systems.

It has been observed by Shapouri et al. that one can employ the energy use per unit of purchase price for portions of a total system to infer the importance of the capital energy contribution.¹² The estimated capital contribution of farming and ethanol manufacture is on the order of 1 percent of the total energy input to ethanol production. Further, the manufacture of other inputs, for example, fertilizers, chemicals, and refined fuels should not materially change this approach, since those industries have relatively small capital charges compared to variable charges in their respective costs of production.

Net Energy Balance Considerations

Shapouri et al.¹² reported that the average energy associated with transporting corn from local storage facilities to ethanol plants was 5636 Btu per bushel of corn or approximately 2120 Btu/gallon of corn ethanol; determined by employing the GREET model. Unlike Dr. Pimentel's 2003 report^{12,13} Shapouri's above referenced report is based on a straightforward approach employing highly regarded quality data from the 2001 Agricultural Resource Management Survey published by USDA Economic Research

Service, USDA's 2001 Agricultural Chemical Usage, and 2001 Crop Production assembled by its National Agricultural Statistics Service, and the 2001 survey of ethanol plants.¹² Dry mill plants are built primarily to produce corn ethanol. Wet mill plants are biorefineries and produce a wide range of products, for example, ethanol, high fructose corn syrup, starch, food and feed additives, and vitamins. Thermal and electrical power are the main types of energy used in dry mill process plants which use natural gas to produce steam and purchase electricity from an electrical power generation station (EPGS) using 1.09 kWh of electricity or approximately 34,700 Btu of thermal energy (low heating value, or LHV) per gallon of corn ethanol. Taking into account energy losses to produce electricity and natural gas the average dry milling corn ethanol plant consumed 47,116 Btu of primary energy per gallon of corn ethanol produced in 2001.

The average energy required to transport corn ethanol from corn ethanol plants to refueling stations also estimated using the GREET model was 1487 Btu/gallon. Shapouri et al. also reported employing the ASPEN Plus process simulation program to allocate the energy used separately to produce corn ethanol via dry mill plants (referred to by authors as ethanol conversion) and DDGS by-products (coproduct energy credits).¹²

The energy used to produce and transport corn to ethanol plants was also allocated separately to starch and other corn ethanol components. However, starch only is converted to ethanol. Therefore, on average starch accounted for 66 percent of the energy used to produce and transport corn was allocated to ethanol and 34 percent to by-products. Energy used in the production of secondary inputs, for example, farm machinery equipment, cement, and steel used in the construction of ethanol plants was not included. All energy inputs used in the production of corn ethanol were adjusted for energy efficiencies developed by the GREET model, for example, 94 percent for natural gas, 39.6 percent for electricity, including a transmission loss of 1.09 percent.

Table 25-1 summarizes the 2001 input energy requirements, by phase of corn ethanol production on a Btu-per-gallon (LHV) basis without by-product credits and also includes the total energy used, the net energy value, and the energy ratio. Table 25-2 represents the same information as described for Table 25-1 but adjusted for coproduct energy credits. The energy ratio is equal to the energy in ethanol (76000 Btu/gallon) divided to the fossil energy inputs related to ethanol production. Accordingly an energy ratio greater than 1.0 reflects a positive energy balance in Tables 25-1 and 25-2 even before subtracting the energy allocated to by-products reflected in Table 25-2.

Production Process	Net Energy Value per Gallon
Corn production	18,875
Corn transport	2,138
Ethanol conversion	47,116
Ethanol distribution	1,487
Total energy used	69,616
Net energy value	6,714
Energy ratio	1.10

TABLE 25-1 Dry Milling Process Distributed Energy Use without Coproduct 2001 Energy Credits

Production Process	Net Energy Value per Gallon
Corn production	12,457
Corn transport	1,411
Ethanol conversion	27,799
Ethanol distribution	1,467
Total energy used	43,134
Net energy value	33,196
Energy ratio	1.77

TABLE 25-2 Dry Milling Process Distributed Energy Use with Coproduct 2001 Energy Credits

Referring Table 25-2, notice that the net energy value per gallon in average dry mill ethanol conversion with a DDGS coproduct in 2001 was estimated to be 27,799 Btu. Furthermore, the net energy value per gallon associated with DDGS (as a credit) was estimated to be 19,317 Btu or approximately 41 percent of the latter total, which is rather significant. It is for this reason that we have now directed our efforts on further reducing the energy associated with the conversion of DDGS and use of available waste energy as steam for reducing prime energy distillation and evaporation requirements of the corn ethanol as shown in Fig. 25-3.

Second Law Considerations

From a second law (or exergy) perspective,^{14,15} however, the advantages of our proposed CHP-based ISJR/FCS alternative can be verified by exploring the related current versus proposed corn ethanol dry milling production availability issues to reflect the higher utilization of prime natural gas (NG) initial energy content via coincident on-site electricity and high temperature waste from the gas-fired CTG exhaust versus imported EPGS electricity with transmission losses to on-site EPGS meter and natural gas firing for operation of distillation and S’ evaporation equipment.

In its most fundamental form, the second law efficiency is defined as

$$\eta_{II} = \frac{\text{available energy in useful products or work}}{\text{available energy supply in "fuels"}}$$
(25-1)

Fortunately, useful methods have been established to calculate the above ratio for various mechanical, chemical, and thermal processes. Therefore, Eq. (25-1) can be expressed as the first law energy ratio with each term multiplied by a quality factor C which reflects the fraction of available energy that can be withdrawn, namely,

$$\eta_{II} = \frac{C_2 \Delta E_2}{C_1 \Delta E_1}$$
(25-2)

Fortunately, quality factors have been computed for many heat and work energy types; for electricity and hydrocarbon fuels the C factor is 1.0 and for steam C is a function of pressure. It should be recognized that in most absorption refrigeration systems of the type characterized involving a proposed hybrid freeze concentration process shown in

Figs. 25-6 and 25-7 and brine regeneration of lithium bromide (LiBr) represents a substantial portion of the prime NG energy input for evaporation of soluble mother liquor but which in the case of the combined vapor recompression absorber (VRA)¹⁶ and LiBr generator operations are provided by steam generated by CTG waste heat prior to discharge of turbine exhaust gases to ambient.

Furthermore, the ΔE ratio in Eq. (25-2) corresponds to the first law efficiency of the process, so the second law efficiency expression simplifies to

$$\eta_{II} = \frac{C_2}{C_1} \eta_I \quad (25-3)$$

Notice Eq. (25-3) establishes that η_{II} will always be equal to or less than unity. Some advanced EPGS steam power plants, for example, have been cited to have first law efficiencies approaching $\eta_I = 45$ percent yet a corresponding second law evaluation yields $\eta_{II} = 33$ percent.

Since most of the irreversible losses occur in the EPGS steam boiler, for which $\eta_I = 91$ percent while $\eta_{II} = 49$ percent for a typical EPSG unit. Therefore to compare the mentioned current ethanol dry mill process with the proposed CHP-based ISJR/FCS alternative process modifications which from the standpoint of availability utilization, a second law efficiency ratio R_{II} must be multiplied by the ratio of actual energy consumed, namely,

$$R_{II} = \frac{\Delta E_1}{\Delta E_2} = \left[\frac{\eta_{II_2}}{\eta_{II_1}} \right] \quad (25-4)$$

It can be seen that the second law efficiencies in Eq. (25-4) serve to normalize the actual energy consumed to the availability of the initial natural gas (hydrocarbon) fuel source. Values of R_{II} greater than unity indicate that process 1 (hopefully our proposed CHP-based alternative) is the more efficient one.

Graboski¹⁷ has estimated that the barrels of crude saved per barrel of ethanol in both wet and dry mill methods in 2000 averaged 0.58, based on a 200 proof ethanol production energy input of 55,049 Btu/gallon of ethanol. Incremental industry improvement in the subsequent next four years (2000 through 2004) showed a 13 percent reduction both in ethanol production energy expended and by-product credit also reported in Btu per gallon.

Graboski¹⁷ also considered the net (variable) energy as the sum of the energy content related to ethanol and avoided energy related to dry and wet mill coproducts less the energy of all inputs. He then defined the energy ratio as the output energy in ethanol divided by the input energy after adjustment for the coproduct credit. As a result, a positive net energy indicates a process that contains more product energy than inputted fossil fuel. Also a net energy ratio greater than 1.0 suggests a process that produces more energy output in liquid fuel than is consumed as fossil fuel and therefore has major GHG implications. He reported the energy ratio for 2000 as 1.21 with an improved 1.32 extrapolated to 2004, and a further extrapolation to an energy ratio of 1.4 estimated for 2012.

Ethanol Economic Realities Reexamined

On March 2, 2008, *St. Petersburg Times* ran a feature article entitled "New Research Says Ethanol Is Far Worse for the Planet than Gasoline. So Why Is Florida Spending Millions

to Promote It?" In preparing our analysis we asked ourselves this same question based on the following most current statistics developed from the following sources: Florida Department of Environmental Protection; Florida Department of Agriculture and Consumer Services; the U.S. Energy Information Administration and Renewable Fuels Association:

1. In 2007 65 billion gallons of ethanol was produced in the United States.
2. These 65 billion gallons would be consumed within 17 days by U.S. drivers.
3. In 2007 and 2008 \$50 millions of Florida was committed to ethanol projects.
4. There were no barrels of ethanol produced in Florida in 2007.
5. The estimated 2017 Florida annual ethanol production is 75 million gallons.
6. The estimated annual gasoline consumption in Florida by 2017 is 11.9 billion gallons.

Professor Mark Z. Jacobson of Stanford University was quoted as challenging statements made by Jeremy Susac, director Florida's Energy Office that the "latest research is flawed and that ethanol offers deep cuts in greenhouse gas emissions and even if ethanol turns out to be a major polluter; as bad as gasoline, he would still back it so why not stimulate production in-house."

Jacobson stands by the results of his own research, which he was quoted as showing "that using ethanol instead of gasoline could make air quality worse; so there's no reason to think that ethanol will reduce carbon emissions since there's no legitimate study in the world that shows that."

In terms of current production methods used in the manufacture of ethanol, we would tend to agree with Jacobson. However, based on our independent evaluation of current methods of producing ethanol by the dry mill process, it can be shown that there is an excessive waste of prime energy in current processing methods shown in Fig. 25-3. Provided available waste energy could be harnessed, Susac's statements may also have considerable merit.

For example, consider the possibilities of achieving a major reduction in both energy use and associated GHG emissions if waste heat from a on-site gas-driven CGT generator could be configured to produce electricity with the exhaust gas normally discharged to ambient was instead used to drive a novel freeze concentration unit in lieu of fossil fuel-fired and evaporation equipment for extracting and processing S and also eliminate the energy required to distill the ethanol by substitution of waste heat for prime natural gas- or coal-fired energy and significantly reduce imported electricity (from a remote power station) by eliminating the concentration of earlier mentioned mother liquor S' evaporation shown in Fig. 25-3. Reducing GHG emissions is a further benefit of NG fuel substitution with waste steam by employing proposed alternate ethanol processing configuration shown in Fig. 25-4. Figure 25-5 presents the integration of ethanol process with CHP schematic.

Accordingly, we must begin, immediately, seeking ways to

1. Minimize the use of prime fuel in corn ethanol fuel processing by incorporating greater use of available high temperature waste heat from synergistic cogeneration, operations, for example, on-site gas-fired turbine or engine-driven power generation equipment.

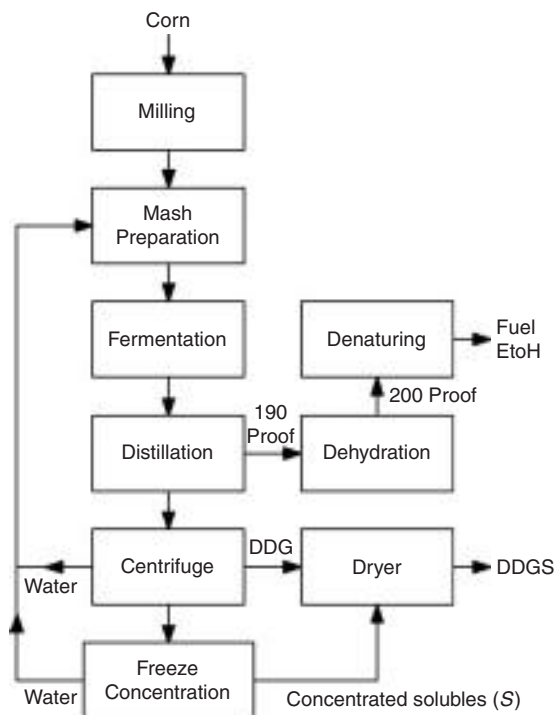


FIGURE 25-4 Alternate ethanol process.

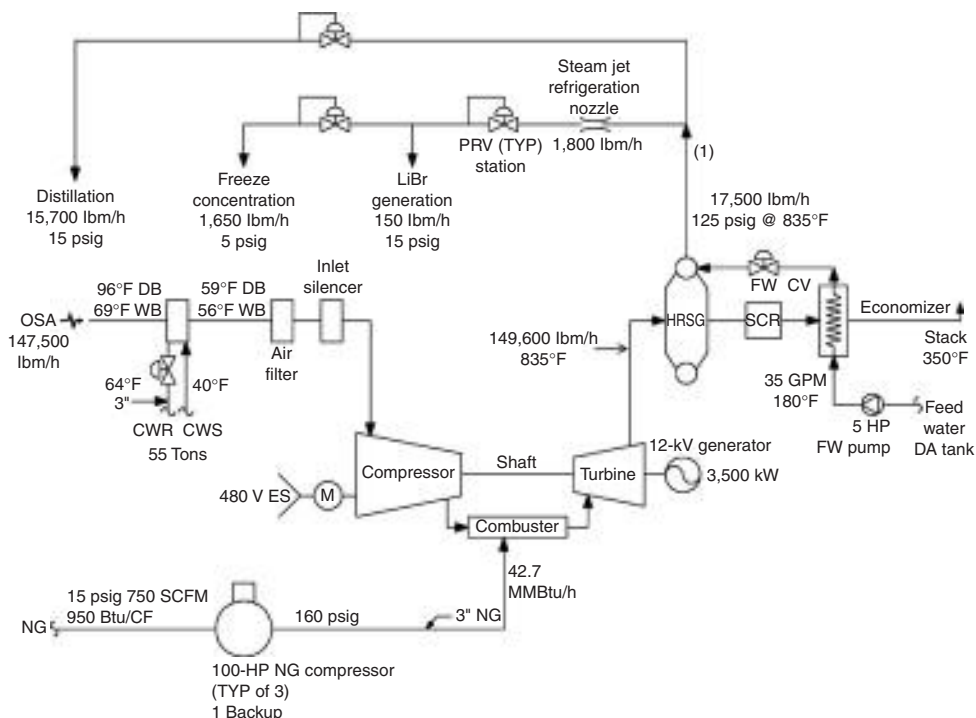


FIGURE 25-5 Integration of ethanol process CHP schematic.

2. Reexamine current corn ethanol processing methods with an eye toward reducing its complexity and high cost by combining and streamlining operations while minimizing use of prime energy fuels if the ethanol industry is grown to the projected scale of operations shown in Fig. 25-1, if it wishes to avoid further adverse (negative) net energy benefit challenges a reference by Jacobson and other knowledgeable engineering professionals.

Related Environmental Eco-Footprints

Environmental perspectives are unbalanced when comparing the cost of electricity and natural gas delivered to building utility meter. Recalling that natural gas-fired electric utility plants operate around 35 percent average annual efficiency (or fuel energy utilization) and CHP plants operate between 70 to 85 percent fuel energy utilization (dependent on waste heat usage—total utilization as well as heating versus cooling), it is essential to compare their environmental impacts on a fuel-source basis and not a delivered to on-site metered-cost basis. Also, the relative annual average cost of natural gas on a dollar-per-unit volume or electricity on a dollar-per-kilowatthour delivered basis to any U.S. location is inherently site-specific and will vary depending upon applicable rate structures. When considering sustainability from an environmental standpoint, one must first estimate the energy content of fuel delivered to the serving electric utility for each purchased kilowatthour delivered versus the energy content for each 1000 ft³ (28.3 m³) of natural gas delivered on a comparable source-energy basis adjusted for transmission losses.

Accordingly if the extensive use of prime energy currently used to process corn ethanol in dry mill processing were provided by waste heat from CGT exhaust from integration with a matched on-site CHP facility whereby all required plant motive power needs including electricity for operation of freeze concentration, centrifuge, and associated pumps to facilitate absorptive and steam jet refrigeration cooling to concentrate S' directly from centrifuge (see Fig. 25-5).

The freeze concentration utilizes an integrated two-stage dual fluid brine coolants to bring about the formation of ice from the S' feed solution thereby achieving a concentrated S syrup coproduct and a water (ice melt) product. Referring to Fig. 25-6, notice that the first stage comprises a steam jet refrigeration component where a sodium chloride (NaCl) brine is chilled by vacuum-induced removal via high-pressure steam venture jet nozzle which serves to both cool incoming S' feed and concentrated aqueous LiBr solution in downstream absorber-freezer (A) as shown in Fig. 25-6.

Concentrated LiBr solution produced by upstream VRA provides the second stage of refrigeration by direct absorptive cooling in the absorber-freezer. Incoming S' feed initially cooled in heat exchanger HX-1 by ice melt delivered from melter-washer (W) is next delivered to HX-2 where it is subsequently cooled by NaCl brine prior to entering rotating spray in lower chamber of the absorber-freezer. Cooled S' is then delivered to the melter-washer creating a cooling effect sufficient to permit ice crystals to form on its interior chamber walls. Cool dilute LiBr from absorber is delivered to VRA for concentration and is returned to the absorber-freezer spray header as concentrated aqueous LiBr solution.

The melter-washer is similar to a flotation tank; a rotary skimmer removes the ice from the S' mother liquor resulting in a concentrated S syrup coproduct. Steam exiting

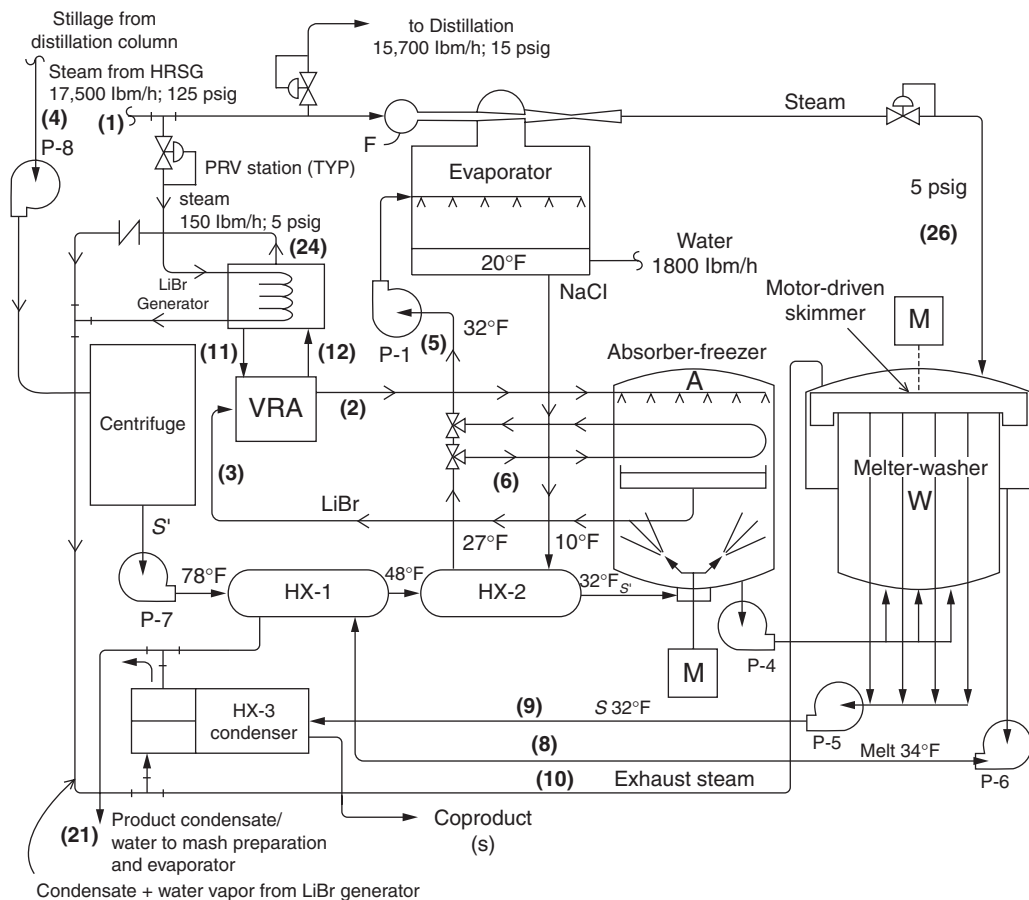


FIGURE 25-6 ISJR/FCS steam, condensate, and VRA flow schematic.

the steam jet refrigeration nozzle is distributed to one of three pressure-reducing valve (PRV) stations supplying low-pressure steam to the distillation column, melter-washer, and LiBr generator for removal of water vapor which is combined with exhaust steam from the melter-washer prior to entering HX-3, where it is condensed by chilled *S* syrup to provide purified, product water. This water is then recirculated to initial mash preparation and evaporator (see Fig. 25-4) to maintain water balances necessary for ensuring *S'* concentration uniformity when maintaining a predetermined continuous corn ethanol dry milling process throughput.

Employing CGT exhaust to produce 125-psig (waste) steam from a companion heat recovery steam generator (HRSG) shown in Fig. 25-5 facilitates the integration of proposed novel steam jet refrigeration, freeze concentration, and vapor recompression absorber (VRA) as illustrated in Fig. 25-6 to achieve water removal at approximately 144 Btu/lbm in lieu of current energy intensive evaporator illustrated in Fig. 25-3 for subsequent concentration of *S'* at approximately 970 Btu/lbm of water; thereby achieving an energy savings of approximately 826 Btu/lbm of water removed amounting to a

significant savings of fossil fuel energy otherwise required for concentration of S' before combining with DDG in a common dryer to produce the desired high energy coproduct DDGS.

Modifications to Corn Ethanol Process

Figure 25-6 illustrates the integration referenced earlier commencing with the HRSG (circuit #1) interconnection supplying 125-psig steam to the steam jet refrigeration ejector nozzle inlet so as to maintain low temperature aqueous sodium chloride (NaCl) brine recirculation within vapor flash tank serving absorber-freezer A (circuit #6) and HX-2 (circuit #5) via pump P-1 as shown.

Upon exiting steam jet ejector nozzle steam proceeds to 15 psig and 5 psig PRV stations to supply heat for processing ethanol within downstream distillation column; for concentration of weak LiBr-water solution within generator serving the VRA (see Fig. 25-7); for utilization within absorber-freezer. After the DDG solids and liquid S' are separated in centrifuge, what remains is a weak aqueous solution of S (designated S') comprising the feed entering heat exchangers HX-1, HX-2, circular absorber-freezer via motorized rotating (bottom) spray and exiting via pump P-4 into the bottom of melter-washer as shown in Fig. 25-6.

The melter-washer comprises a circular housing leading to a vertically disposed wash column into which the product ice slurry is discharged after which it rises to a

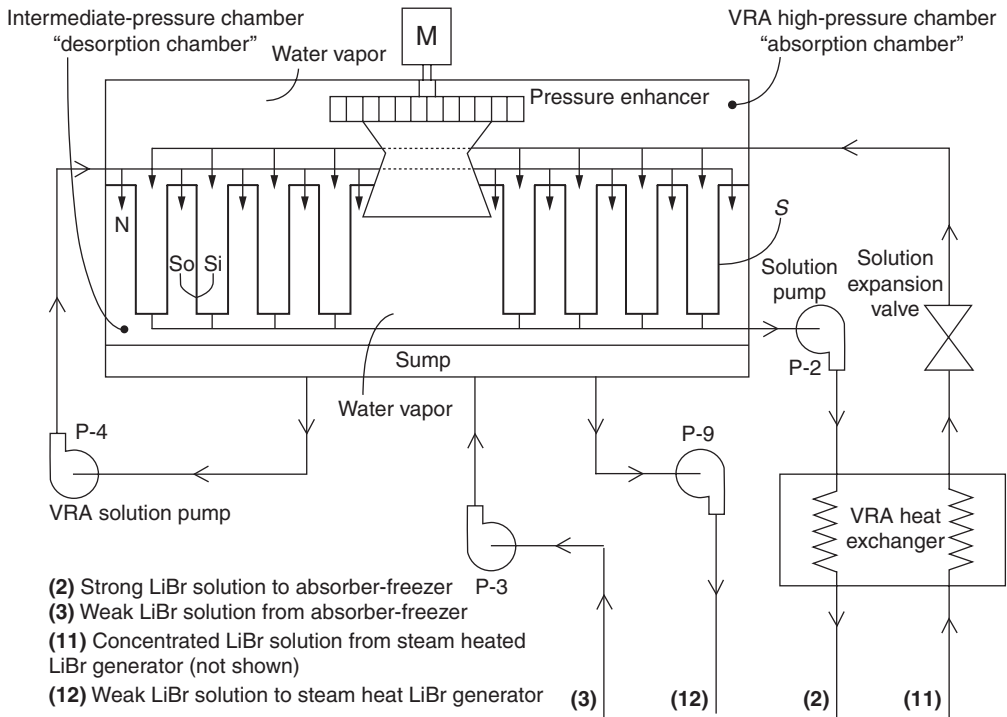


FIGURE 25-7 Vapor recompression absorber (VRA) flow schematic.

floatation level also containing a lip or weir where a motor-driven skimmer operates in a horizontal plane to cause a radial discharge of ice slurry, accumulated at the surface level. A shell covers the top of the housing and surrounds it with a depending skirt that forms an annular melt chamber from which the exhaust steam is passed to melt the ice to purified water (or melt).

Pump P-6 then delivers the product melt through shell- and tube-type heat exchanger HX-1 in a counterflow manner which serves to cool incoming dilute S' feed solution delivered from pump P-9 while concurrently raising exiting product melt temperature. Excess steam (circuit #10) and water vapor exiting steam heated LiBr generator (circuit #24) mix prior to entering condenser HX-3 and upon exiting combine with product melt water from melter-washer to comprise purified, product water. Product water is then returned to the upper distillation column as reflux (via circuit #21) and evaporator as shown in Fig. 25-6.

Concentrated S solution exits melter-washer by means of pump P-5 (circuit #9) and is delivered to condenser HX-3 to condense excess steam from jet ejector nozzle (circuit #10) and water vapor from LiBr generator (circuit #9); exiting HX-3 as coproduct S and product water.

Referring again to Fig. 25-6, notice that the absorber-freezer has both primary NaCl and secondary LiBr solution brines respectively comprising circuits #6, 2, and 3. Latter are arranged serially to reduce S' feed internal temperature and to facilitate removal and prompt separation of water via crystallization and subsequent separation within downstream melter-washer (via motorized skimmer) as flaked ice melt (circuit #8), combined excess steam from jet nozzle and water vapor from LiBr generator (circuits #10, 2 and 3) and concentrated S (circuit #9) entering (condenser) HX-3 exiting HX-3 as product water as described above. Coproduct S also exits HX-3 where shown in Fig. 25-6 to be further processed, as shown in Fig. 25-4.

Figure 25-7 illustrates the cross section of the circular VRA unit comprising two separate chambers:

1. One is operating at a VRA high pressure
2. The other is operating at the intermediate pressure of the absorber-freezer (see Fig. 25-6)

In the VRA high-pressure chamber, absorption occurs, and in the intermediate pressure chamber, desorption occurs. They are separated by a heat-transfer surface. A variable-speed centrifugal compressor, the pressure enhancer, which is powered by the electric motor (M), connects these two sides and the concentric walls maintain the needed pressure differential for a COP of approximately 1.2.

Incoming concentrated LiBr solution (circuit #11) from an external steam heated LiBr generator is sprayed in the VRA high-pressure chamber over the inner side (Si) of the heat transfer surface. Simultaneously weak LiBr solution from circuit #3 supplied by pump P-3 goes into the intermediate-pressure chamber of the VRA and then is sprayed over the outer side (So) of the heat transfer surfaces by the VRA solution pump. Concentrated LiBr solution is returned to the spray nozzles of the absorber-freezer via pump P-8 and circuit #2. Falling film evaporation of the water refrigerant results in this chamber due to the temperature difference created by the previously referenced refrigerant vapor compressor interconnecting the two chambers. The evaporated refrigerant vapor, at intermediate pressure, is drawn through the inlet side of

the compressor and delivered to the VRA high-pressure chamber, where it is supplied directly to the inner surface (Si) via circuit #11, where it is absorbed by sprayed concentrated LiBr solution from the LiBr Generator and returns to the LiBr generator via pump P-9 through circuit #12 for regeneration of the returning weak LiBr solution involving the evaporation of water vapor within the LiBr generator and discharge of water vapor via circuit #24 to mix with exhaust steam emanating from melter-washer via circuit #10 prior to their both being condensed in HX-3 and exit as product water as shown in Fig. 25-6.

The remaining concentrated LiBr solution is collected in a common manifold located above the sump as shown in Fig. 25-7, prior to exiting the VRA at a higher temperature and concentration but at the desired intermediate pressure exiting via pump P-8 to circuit #2. In the partial freezer concentration cycle illustrated in Fig. 25-7, the required companion VRA as presented by Ludovisi et al.^{18,19} operates essentially as a second-stage LiBr absorber-refrigerant heat pump/regenerator to complete the proposed combination steam jet refrigeration/freeze concentration cycle (SJR/FCC) which is intended to eliminate the need for an evaporator to concentrate mother liquor S' from the centrifuge; and eliminate the need for an evaporator prior to recombining the separately extracted S and DDG components in dryer as shown in Fig. 25-4.

Looming U.S. Trade Gap Issues

On March 12, 2008, *Wall Street Journal* reported that "The U.S. trade deficit widened slightly in January as strong American exports were more than offset by higher prices for imported oil." Essentially what was implied, but not yet factored into the "pro and con" economic arguments on the advisability of continued ethanol expansion in the face of a growing trade gap as rising oil costs appear to offset our lower dollar valuation benefit from our perceived "export strength." Interestingly enough the cost of imported crude oil in January, 2009 hit a record \$39.5 billion which was based on a then record average price for crude oil per barrel of \$84.09.

Approximately 4 months later on May 9, 2009, crude oil hit a daily high of \$126.20 per barrel or approximately 50 percent higher than January's "record numbers." Based on projected crude oil futures on that same date, crude oil import costs were expected to reach \$150 per barrel as 2008 progressed. Should imports rise higher as a result of both higher crude oil cost and demand, and should U.S. exports also decline (due to constrained overseas markets), the ability to substitute corn ethanol for refined crude as gasoline, at whatever percentage is available from production goals projected in Fig. 25-1 could still provide a substantial indirect benefit for all Americans.

Recent congressional calls for the curtailment of U.S. ethanol production goals discussed earlier in response to the continuing worldwide rise in the cost of food are unfounded when increased U.S. corn crop efficiency and production;¹¹ higher energy transportation and related costs; higher demand for food protein from China, India, and other formerly developing nations (have significantly reduced their own food production acreage for industrial growth benefit, etc.) are factored in. Such arguments serve only to benefit crude oil exporting nations at the expense of U.S. citizens also struggling under the rising cost of energy and increased demand for similar foods from rising (and wealthier) overseas populations.

Summary of Findings

Shapouri et al.¹² reported that 1.09 kWh or 34,700 Btu/gallon of corn ethanol produced in the dry milling process are required for electric power needs. In Fig. 25-5 a 3.5-MW (or 3500 kW) CGT on-site CHP system diagram is shown providing the proposed on-site electrical power alternative for our hypothetical study case. Subject synchronous electrical generator enables a predetermined a 3211-gallon ethanol per hour ethanol conversion rate. From Table 25-1, notice that the energy needed for ethanol conversion currently requires 47,111 Btu/gallon of ethanol for the combined electrical and prime energy thermal inputs via dry mill processing illustrated in Fig. 25-3. With this data, we can determine the prime energy thermal separately from Table 25-3 as $47,111 - 34,700 = 12,411$ Btu/h or an NG equivalent input of $16.3 \text{ ft}^3/\text{gallon}$ of ethanol converted, assuming 80 percent efficiency.

Referring to Sherif et al.,²⁰ we can employ published data to estimate the performance of the steam jet ejector nozzle shown in Fig. 25-5 and in Fig. 25-6 as letter F. Referring again to Fig. 25-5, notice that at rated design conditions, 17,500 lbm at 125-psig/h corresponding to an enthalpy of 1220 Btu/lbm can be generated from reclaimed waste heat at the HRSG by heat transfer with 149,600 lbm/h of 835°F CTG exhaust gases exiting to ambient through stack at 350°F. Next, after first extracting 15,700 lbm/h of steam following passage through pressure reducing valves to 15 psig for a direct savings of (4767 Btu/gallon ethanol) at the distillation column, the remaining balance or 1800 lbm/h at 125 psig (or 8 bar) and 374°F (190°C) motive steam flows through the steam jet ejector to maintain required NaCl refrigeration evaporator pressure. Upon exiting, steam enters the respective pressure reducing valves at indicated reduced pressures shown in Fig. 25-5 to provide for operation of the combined freeze concentration melter-washer (W), associated VRA, and LiBr generator thermal requirements shown in Fig. 25-6.

Referring to Fig. 25-6, notice that HX-3 which serves to condense combined excess steam from melter-washer (W) and mixed vapor/condensate from LiBr generator functions as the steam jet refrigeration condenser for the ISJR/FCS cycle operating at an estimated 0.8 coefficient of performance (COP) to maintain designated NaCl brine conditions also shown in Fig. 25-6.

Reducing the current dry mill ethanol conversion prime NG thermal requirement is enabled by substituting available waste energy via ISJR/FCS for the deleted S' evaporator

National Average	
Annual CO ₂ reduction (lb)	24,906,202
Annual CO ₂ reduction (%)	19
Northeast Average	
Annual CO ₂ reduction (lb)	8,175,425
Annual CO ₂ reduction (%)	8
Western Average	
Annual CO ₂ reduction (lb)	15,492,846
Annual CO ₂ reduction (%)	14

TABLE 25-3 3.5-MW CHP versus EPGS CO₂ Reduction

Production Process	Net Energy Value Per Gallon
Corn production	12,457
Corn transport	1,411
Ethanol conversion	15,974
Ethanol distribution	1,467
Total energy used	31,309
Net energy value	44,691
Energy ratio	2.43

TABLE 25-4 Dry Milling Process Distributed Energy Use with DDGS Coproduct and 11,825 Btu/Gallon Energy Credits

saved an additional 1800 lbm/h × (975–144) Btu/lbm which translates to a 465 Btu/gallon ethanol NG saving (see Fig. 25-5). Next utilizing the 15700 lbm/h waste steam for operation of distillation column an additional 4767 Btu/gallon ethanol saving results in a combined energy credit of 5232 Btu/gallon ethanol. Furthermore, since the EPA data based national average EPGS consumes on average, 19 percent more NG than conventional CHP shown in Fig. 25-5, the energy ratio which was based on a 76,000 Btu/gallon ethanol energy benchmark, enables CHP electrical power thermal equivalent to be reduced from 34,700 to 28,107 Btu/gallon ethanol for a conventional CGT-driven on-site CHP system of the type illustrated in Fig. 25-5 corresponding to a 6593 Btu/gallon ethanol energy credit results in a combined 11,825 Btu/gallon ethanol conversion energy credit as shown in Table 25-4.

Next comparing the energy ratios of Tables 25-4 and 25-2, notice the sizeable difference in the values of their respective net energy ratios reflecting a 37.3 percent gain attributable directly to the benefits resulting from the proposed ISJR/FCS dry mill processing enhancements.

Finally one is now able to compute the annual operating savings resulting from energy credit mentioned earlier to determine the number of years needed to amortize the initial \$7 million CHP first cost including the estimated incremental additional cost of ISJR/FC systems (after crediting the evaporator cost eliminated) shown respectively in Figs. 25-3 and 25-5 through 25-7. Assuming a 80 percent heat transfer efficiency for current NG-fired equipment now proposed to be heated by waste steam, one also obtains a 5232/950 (LHV) Btu/ft³ NG × 0.8 = 6.88 ft³/gallon-h ethanol savings; Based on \$10/1000 ft³ NG, for processing 3211 gallons/h of corn ethanol on an average 300 day 24/7 daily basis, or 7200 annual “ethanol conversion operating hours,” one is able to compute an estimated annual operating cost savings for the proposed alternative ISJR/FCS at \$1,590,800 thereby resulting in an estimated near-term 4.4 year simple payout available to amortize the initial additional capital investment required to implement the proposed dry mill process enhancements.

Comparison of CHP and EPGS Eco-Footprints

Table 25-3 shows that conventional CGT-powered CHP systems of the type illustrated in Fig. 25-5 results in lower than corresponding EPGS CO₂ emissions by as much as 20 percent. Additionally, Table 25-5 shows that such CHP systems also result in lower

National Average	
Annual NO _x reduction (lb)	60,473
Annual NO _x reduction (%)	37
Northeast Average	
Annual NO _x reduction (lb)	20,614
Annual NO _x reduction (%)	20
Western Average	
Annual NO _x reduction (lb)	42,787
Annual NO _x reduction (%)	31

TABLE 25-5 3.5-MW CHP versus EPGS NO_x Reduction

than corresponding NO_x emissions by as much as 37 percent. These findings were calculated using data from the EPA's eGRID2006, which provide power plant emissions data for the year 2004. Since generation technologies, fuel types, and age of plants vary widely between regions, the calculations include a comparison using data from the western U.S., northeastern U.S., and the national average.

Shapouri et al. also reported an energy ratio of 1.10 for dry milling process distributed energy use without coproduct 2001 energy credits; and a energy ratio of 1.77 on the same dry milling basis but with coproduct energy credits included.¹² Therefore, the direct benefit from utilizing the hybrid ISJR/FCS process described above resulted in a $[(2.43 - 1.77)/1.77] \times 100$ or a 37.3 percent reduction in production energy use, which if implemented would improve the estimated economic benefit over current dry mill ethanol processing methods. This has caused some concerns about whether or not ethanol substitution for refined gasoline is commercially viable at current lower corn commodity cost without substantial government subsidies, and which Congress has debated, whether or not should at some point be substantially reduced.²¹

Conclusions

If annual corn ethanol production quotas are to grow as the most significant, near-term petroleum substitute at a rate consistent with current expectations as projected in Fig. 25-1, it must be sustainable from both a cost-effective and environmental standpoint in addition to conforming to the requirements of the earlier referenced new energy legislation approved by Congress and signed by President Bush in December, 2007.

Clearly that is not the case among corn ethanol industry trade groups and producers, designated state and federal authorities having jurisdiction, public policy professionals, knowledgeable engineers, scientists, growers, and agricultural and engineering academics as cited earlier.

Equally as important, there must be a consensus among our energy and policy experts, that there is, in fact, a net savings in energy available to consumers on a Btu-per-gallon basis and on a mile-per-gallon basis when comparing commercially available corn ethanol versus regular gasoline at the pump. Equally as important there must also be a consensus among our environmental and economic experts that there are no irreversible environmental issues concerning current expectations that all related GHG

emissions will not be exceeded or that U.S. consumer cost and availability of corn-based human and livestock foods will not be negatively impacted over time as corn ethanol production ramps up.

After addressing current dry mill ethanol production technologies, available ethanol production energy use statistics, studies, and related GHG emissions, it became apparent that major first cost and annual energy use savings along with, related GHG emissions reductions could be obtained if on-site CHP could be economically integrated with the current dry mill corn ethanol processing sequence as shown in Fig. 25-5. That is, provided the CHP portion would also operate 24/7 to permit substitution of available waste heat for prime energy use, thereby significantly reducing the associated GHG emissions.

Therefore assuming the above criteria based on each Btu required on-site for corn ethanol production, approximately 4.9 to 4.6 Btu is expended by natural gas in remote steam EPGS boilers with annual operating efficiencies of 75 to 80 percent, respectively. Finally, by employing dual use of CGT waste heat-generated steam and by substituting the proposed ISJR/FCS concentration in lieu of current evaporator, one gains a theoretical reduction of approximately 85 percent in energy required to remove a pound of water by proposed freezing versus conventional direct-fired evaporation methods.

Recognizing that existing electric power generation stations (EPGS) operate at an estimated 30 percent annual average thermal efficiency versus a probable 75 to 80 percent annual CHP fuel and equipment utilization.

Furthermore, after adjusting for annual average transmission losses of approximately 10 percent (for electricity) and 9 percent (for natural gas), the gas-fired utility energy and GHG differentials at the serving EPGS would correspond to approximately 5.4 to 5.1 times the annual GHG emissions generated by a on-site CHP system, respectively, operating at 75 to 80 percent annual operating efficiency.

As the cost of natural gas and electricity continues to rise, the time required to amortize the additional CHP capital investment can be expected to drop significantly particularly if the "cap and trade" of GHG emission credits now in effect in many of the European Union countries is adopted. The size of the current carbon trading market has grown significantly in recent years. For example, in 2005 it was estimated to be approximately \$15 billions; increasing to approximately \$35 billions in 2006 and most recently estimated in 2007 to have reached \$62 billions.

The cap-and-trade approach,²² currently being discussed in Congress, would establish an annual "cap" on GHG emissions based on current facility operations which if exceeded would allow it to continue to operate through purchase of certifiable "credits" from another facility having reduced its GHG load by plant improvements, for example, either directly or through a broker. Accordingly, if Congress should pass legislation to adopt a similar "cap and trade" policy current ethanol processing facilities which adopt similar or equivalent GHG reduction measures to those proposed could then sell their "GHG credits" to another firm to further offset their additional CHP and ISJR/FCS capital investment.

Organization of the Petroleum Exporting Countries (OPEC) members not surprisingly appear less inclined to increase crude production beyond current levels. Since its inception 47 years ago, OPEC until recently was a cartel in name only. In 1999, however, with crude pricing at \$110 a barrel, supply remained basically unregulated with demand cut by 1997 to 1998 Asian financial crisis issues. Consequently Saudi Arabia decided to meet with all other major producers and negotiated an agreement to cut production dramatically to avoid the future collapse of its oil revenues. From that time on until the present OPEC truly became cartel.²³

By failing to reduce our dependence on crude imports, through greater ethanol production and a similar cap-and-trade type policy, and which today comprises approximately 60 percent of our annual consumption will depress our economy and ultimately our standard of life. OPEC's control of world combined supply and cost has now become a reality, with upward pressure subject to geopolitical and perceived supply concerns. It is against this background that the cost-to-benefit aspects of our current ethanol subsidies and not the singular issue of net energy cost of gasoline versus ethanol per mile traveled comes into play.

Furthermore with the rising cost of finding new crude supplies in friendly places; with high energy demand from China and India's potentially unsustainable building²⁴ growth likely to continue for years at current or higher growth rates; with low profitability in refining discouraging further investment; and with understandable environmental and other planning uncertainties²⁵ and concerns by adjacent communities can be expected. Added to the above are the unrealistic citizen expectations that renewable and/or atomic energy can be relied upon for significant displacement of energy supplies in the near term.

Therefore, the decision to continue to expand ethanol production capacity principally to come from corn must and can be maintained provided current production energy use and associated GHG emissions can be reduced to the projected levels.

With respect to lowering EPGS associated eco-footprint in terms of GHG and NO_x emissions, it can be seen that the 3.5-MW CHP configuration illustrated in Fig. 25-5 would have reduced EPGS emissions ranging from 8 to 14 percent with a national average 19 percent (Table 25-3) and reduced EPGS NO_x emissions ranging from 20 to 37 percent (Table 25-5) depending upon the proposed location for the subject nominal \$23 million gallon/year dry mill corn ethanol processing plant.

Nomenclature

C quality factor of availability

R efficiency ratio

Greek symbols

ΔE change of energy

η efficiency

Subscripts

I first law

II second law

1 supplied; process 1

2 useful; process 2

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CHAPTER 26

Case Study 8: Energy Conservation Measure Analysis for 8.5-MW IRS CHP Plant

Milton Meckler

This chapter describes the application, various alternatives, and results of energy conservation measures (ECMs) implemented at a 522,000 ft², five-building complex leased by the Town of Brookhaven, Long Island, to the General Services Administration (GSA) for use by the Internal Revenue Service (IRS). The IRS has a number of such regional automatic data processing centers located around the country, but this was the only one known that was to be served by an on-site CHP system at the time of the subject energy management system (EMS) survey.

When the northeast regional IRS center was initially commissioned by the IRS, the northeast United States was already in the grip of an “energy and fuel availability crisis” and the local electric utility was unable to guarantee continuous power supply to this critical GSA facility. As a result the IRS specified a need for an on-site total energy system to satisfy its immediate need for continuous 24/7 power availability with an improved quality required by its sophisticated computer equipment.

Envirodyne Energy Services (EES), a subsidiary of Envirodyne Inc (EI). (NASDAQ), headquartered in Beverly Hills, California, became responsible for the management and operation of a 8.5-MW, 3600-ton CHP system (designed by a prior EI subsidiary) comprising six 10-cylinder, dual-fuel engine-driven synchronous generator sets provided with heat recovery from engine jacket and exhaust heat exchangers (Fig. 26-1). The CHP plant included three motor-driven and two absorption chillers. It also included one natural gas engine-driven centrifugal chiller and supplementary gas-fired boilers and was designed with 100 percent redundancy available within the above referenced generating and supplementary boiler systems and 50 percent redundancy available in both chiller and air-conditioning capacity. It was the only source of local utility power



FIGURE 26-1 Ten-cylinder, dual-fuel-driven synchronous generator sets.

interconnection for emergency power needs, and was carefully monitored by three shifts, 24/7 operating crew, so that then prevailing high utility interconnection costs were minimized without sacrifice of overall year-round reliability and normal servicing needs or potential failure of any individual CHP plant equipment.

Subsequently when a ECM program initially requested by the Town Council, EES was in a unique position to quickly respond, since not only had EES (and its predecessor firm) been tasked with designing and operating the CHP system but it had also been retained to provide 24/7 operation and maintenance service for the entire IRS facility, including at a later time, its internal distribution system, in all, a major responsibility.

The energy conservation program initially identified 10 major areas of opportunity with the overall IRS facility and included some proposed low-cost modifications related to the CHP plant. The local EES staff identified and estimated numerous low-cost ECM savings; as one example, it found that implementing simple thermostat adjustments could result in 9600 MBtu/year savings. By addition of selected fenestration control employing IRS staff managed window shades could result in an additional 40 MBtu/year at a relatively low capital cost of approximately \$10,000 which as pointed out to the Town Council could be rapidly amortized by above cited reductions fuel consumption. Fuel oil consumption costs were escalating rapidly by approximately 300 percent from its initial cost, in the space of only 1 year due to local impacts from the emerging Middle East oil embargo.

ECMs recommended and implemented by EES included

1. Resetting approximately 300 interior IRS facility thermostats from 75°F initially to 70°F; subsequently to 68°F. Estimated savings: 9600 MBtu/year.
2. Remove two 40-W fluorescent lamps from each of approximately 5000 initially installed four-lamp ceiling fixtures while still maintaining adequate lighting level standards for IRS employee tasks. Estimated savings: 32 MBtu/year.

3. Turn off lighting fixtures in all unoccupied office areas during off-hours. Estimated savings: 15 MBtu/year.
4. Remove two 1000-W mercury vapor lamps from each of the approximately 65 four-lamp poles in the IRS employee and visitor parking lot while still meeting safe illumination standards. Estimated savings: 1600 MBtu/year.
5. Reset humidity dew point control to 60°F from initial 54°F set point. Estimated savings: 19 MBtu/year.
6. Turn off snow-melting equipment installed in earlier referenced parking lot, requiring operating the redundant engine generator set to carry the additional required 1700 kW load capability for potential inclement local weather. Estimated savings: 1900 MBtu/year.
7. Shut down all air-handling units during off-hours. Estimated savings: 3300 MBtu/year.

Conduct in-house evaluation of CHP plant operating efficiency as a means of identifying additional ECM, commencing with a thorough equipment and controls check which normally would not have been undertaken in a CHP plant then slightly less than 2 years old. EES operating staff started at the beginning and worked all the way through each CHP energy production, control, and use system. It also provided an additional incentive to fine-tune CHP plant operations, rebalancing the chiller and air-handling system flows including checking, adjusting, and recalibrating controls where found necessary.

In reviewing the results of the overall proposed ECM program EES had to select a year-to-year time period, where CHP plant and IRS offices remained about the same after normalizing monitored energy use for weather, the number of man-hour days, plant and IRS facility equipment operating hours, etc. Therefore by noting the reduction in fuel consumed in several arbitrarily selected time periods against fuel consumption for the same time period, 1 year later. For example, the average monthly electrical consumption in a 3-month baseline period for the coldest months; namely, from December 1 through February 28 was determined to be 1,173,333 kWh. For the same period, 1 year later, after the ECM itemized above were implemented, the average monthly consumption for the same 3-month time period dropped to 933,333 kWh, resulting in approximately a normalized 20.5 percent reduction in electrical usage.

Total fuel consumed in the same differential base time period averaged 255,533 gallons/month; representing the combined fuel oil and natural gas (NG) use (where NG uses was computed in equivalent fuel oil energy value). In the same comparison time period the following year, however, overall IRS facility fuel consumption including its CHP plant averaged only 124,755 gallons/month thereby confirming a 51.2 percent reduction in fuel cost, which our client was required to provide under its contract with GSA at an earlier agreed upon fixed cost, without escalation, which at the time of its agreement seemed unlikely based on prior year fuel oil cost trends.

Subsequently EES in-house staff was able to demonstrate a 30 to 40 percent average reduction in fuel energy use after comparative year to year energy billings were normalized, as described above, were extrapolated to a full year. On average, the CHP plant system for the IRS facility was designed to operate between 65 and 70 percent efficiency.

Using the lower, more conservative 65 percent efficiency figure, this savings would translate into a 20 to 25 percent reduction in basic fuel demand which added

the 40 percent differential between the utility purchased electricity and on-site CHP plants of the type above translates to an average total annual cost reduction in comparable net energy use reaching upward of 60 percent.

As a result of EES staff efforts, the Town Center client received a major cost saving benefit at relatively low first cost to implement and amortize. That is, a point to be well taken by all owner-operator CHP plants, now and in the future, particularly when the world may be entering a period of higher operating cost due to overall electrical grid reliability and urgent need for infrastructure upgrades in both the United States and many overseas countries as well.

An important lesson learned from the above case study was that the cumulative annual cost associated with purchasing emergency power from a remote EPGS utility can now be reduced by consideration of less costly alternatives for providing reliable on-site emergency power.

Reviewing CHP Alternatives for Reliable Emergency Power Systems

Over the last several years, continuity of electrical power has become increasingly important not only to individual utility customers, but also to the national and world economies. Meanwhile, confidence has eroded in overstressed and aging utility grids given such events as the Chicago Loop outage of 2000, California's rolling blackouts of 2001, the Northeast blackout of 2003, and the European outages of 2003 and 2006. To ensure that power is available when needed, many businesses are taking control by installing on-site generation.

Time to Consider Following Emergency Power Options

An uninterruptible power supply (UPS) is typically required for critical computer loads, for continuous process manufacturing, or anywhere else where momentary interruptions cannot be endured. A UPS provides ride-through of short-term outages until a generator can come online. Valve-regulated lead-acid (VRLA) batteries, wet-cell lead-acid batteries, and rotary flywheels are among the typical options available for UPS energy storage.

Diesel reciprocating generators are typically selected for standby applications, where utility outages are expected to last (and the generator expected to run) less than 100 hours/year. Diesel gen-sets are attractive for standby applications due to their low initial cost, low maintenance cost, and ease of fuel storage. The low expected annual run times associated with standby applications make the relatively high energy cost associated with diesel fuel a nonissue. In addition, the U.S. Environmental Protection Agency (EPA) emission permitting is usually rather straightforward.

Natural gas reciprocating generators are better suited for small prime or continuous generation applications such as peak shaving or cogeneration. A natural gas generator requires approximately twice the engine displacement of a diesel engine of the same rating, so installed costs are higher than for diesel. In addition, on-site propane storage may be required as a backup fuel source in the event of a failure of the natural gas utility. However, the lower natural gas fuel costs and lower emissions make up for the higher installation costs and propane storage issues if the generator is expected to operate more than 2000 hours/year.

Turbine generators, using steam, natural gas, or oil as a source, can be attractive for large prime or continuous cogeneration applications. Such installations have a relatively

high total installed cost, but are reliable, compact, and quiet, and the emissions produced by a cogeneration installation are relatively low. Turbines can take from 30 seconds to several minutes to come up to speed, so they are generally unsuitable for emergency (life-safety) applications.

Fuel cells hold promise for the future due to their low emissions; however, due to their very high installation and operating costs, they have not yet displaced existing reciprocating or turbine technologies. Costs are expected to drop as the technology matures.

Should CHP be considered for some emergency power generator installations, as a means of leveraging a large generation capital expense by using it to longer-term operating expenses? A generator on its own may have a thermal efficiency of only 20 to 35 percent incorporate it into a cogeneration installation, and the system may achieve a thermal efficiency of 80 percent or greater. A 30 percent efficient generator with 70 percent waste heat also can be viewed as a 70 percent efficient boiler with free electricity. Moreover, a prime generation installation with $N + 2$ generator redundancy can approach the reliability of a traditional generator-UPS system.

Peak shaving is another way to reduce operating costs. Some utilities offer an “interruptible rate,” whereby the customer is requested to start its generator to unload the utility’s distribution system. In addition, some utilities impose higher peak-demand or time-of-use (TOU) rates, making it financially attractive for customers to transfer over to generators on a daily basis during specific time blocks.

Applicable Codes and Standards Issues

During the design phase of a CHP alternative to short-term standby power needs, one also will need to consider federal, state, and local requirements, suitable site selection and redundancy requirements along with several codes and standards, where applicable, that apply to generator installations, including but not limited to the following:

1. Article 702, Optional Standby Systems, NFPA 70
2. Article 445, Generators, NFPA 70
3. Standard TIA-942, Telecommunications Infrastructure for Data Centers
4. Article 517, Health Care Facilities, NFPA 70
5. Article 701 Legally Required Standby Systems, NFPA 70
6. Article 705 Interconnected Electrical Production Sources
7. Article 7020 Emergency Systems

For additional information on related electrical issues, please consult Chap. 11.

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Glossary

The following are some of the key terms one needs to understand when working with CHP facilities.

Bottoming-cycle. A bottoming-cycle produces heat first as the main product, for example, for industrial process heating, and then uses the waste exhaust heat to produce power. Bottoming-cycles are typically in those facilities that have high-temperature process heat requirements.

Building integration diagnostics. Because the thermal output is integrated with existing chilled and hot water distribution loops, there is a need to ensure that the performance of the integrated system is optimal.

Carnot cycle. The maximum theoretical efficiency for a heat engine cycle, which assumes a frictionless, reversible process with isothermal heat transfer and adiabatic compression/expansion, and is a function of the temperature of the high-temperature source and the low-temperature sink.

CHP efficiency. CHP efficiency is equal to the sum of the net electric power output plus the thermal output (i.e., recovered heat) divided by the fuel input in consistent units times 100 percent. Note that in the U.S. Federal Energy Regulatory Commission (FERC) efficiency only gives a 50 percent credit to the thermal output.

Combined cooling heat and power. Combined cooling heat and power (CCHP), also known as *trigeneration*, in addition to the simultaneous production of heat and the generation of power, also uses the recovered waste heat to produce cooling typically with absorption chillers or steam turbine-driven chillers.

Combined cycle. A combined cycle system uses steam produced from recovered exhaust heat to produce additional power in a steam turbine-driven generator.

Combined heat and power. Combined heat and power (CHP), also known as *cogeneration*, is the simultaneous production of heat and the generation of power (typically electric power) from a single fuel source. Operating a car heater on a cold day is a form of CHP.

Combustion. Synonymous with burning, combustion is the chemical reaction whereby a fuel is oxidized producing heat and/or light.

Commissioning verification. Commissioning verification (CxV) is a process by which the actual performance of the individual components in a CHP system and the performance of the CHP system as a whole are verified to comply with the designers' and manufacturers' recommended performance.

Component-level diagnostics. Diagnostic algorithms that monitor component performance on a continuous basis to detect and diagnose faults at the component level

Compression ignition. In compression-ignition internal combustion engines, the fuel-air mixture in the combustion chamber is ignited by the heat of compression. More specifically, the fuel injected in the expansion chamber is mixed with highly compressed air that results in combustion. This method of ignition is in contrast to spark ignition.

Critical operations power systems. Critical operations power systems (COPS) are those systems so classified by municipal, state, federal, or other codes by any governmental agency having jurisdiction or by facility engineering documentation establishing the necessity for such a system. These systems include but are not limited to the following: power systems, HVAC, fire alarm, security, communications, and signaling for designated critical operations areas. COPS are generally installed in vital infrastructure facilities that (1) if destroyed or incapacitated, would disrupt national security, the economy, public health or safety; and (2) where enhanced electrical infrastructure for continuity of operation has been deemed necessary by governmental authority. (Section 708.X Critical Operations Power Systems, Copyright National Fire Protection Association, Quincy, Massachusetts).

Effective electric efficiency. Effective electric efficiency, also known as *fuel utilization efficiency*, is the net power output divided by the net fuel input in consistent units, times 100 percent, where the net fuel input excludes the fuel that would be required for heating in a conventional process. Typically, the conventional process assumes an 80 percent efficient boiler.

Efficiency. In general, efficiency, expressed as a percentage, is equal to output divided by input using consistent units, times 100 percent.

Exergy. Exergy is the maximum amount of work that can be obtained from a source. If the source is a fluid, then the fluid's exergy is defined as its enthalpy minus the product of the atmospheric (reference) temperature times the corresponding reference entropy. Therefore, exergy is a function not only of the properties of the fluid itself (the source) but also of the ambient conditions (the sink).

Exergy efficiency. Exergy efficiency is the total amount of exergy used/consumed divided by the total possible exergy available. Exergy efficiency is one measure of sustainability as it provides a metric to determine how much of the available energy was actually converted to useful energy/work.

Heat rate. The heat rate represents the amount of energy that must be supplied to produce a unit of electrical energy (e.g., Btu/kW). Manufacturers typically provide the heat rate as a metric for comparing engines. A lower heat rate versus a higher heat rate means that less fuel is required to produce a unit of power. Heat rate is the reciprocal of efficiency (accounting for the inconsistent units). Heat rate usually assumes the lower heating value (LHV) of fuel.

Higher heating value. While CHP equipment is typically rated on the LHV, fuel is purchased at the higher heating value (HHV), and therefore engineering calculations must account for this energy penalty (approximately 10 percent).

Lower heating value. The lower heating value (LHV) is the energy released from the combustion of fuel that accounts for the fact that some of the energy released during combustion cannot typically be used beneficially because the energy is consumed in the vaporization of water that was present in the fuel. All CHP equipment is typically rated on the LHV.

Prognostics. These tools are needed to enable operation and maintenance personnel to anticipate and plan for repair and maintenance to maintain performance and minimize down time.

Rankine cycle. The Rankine cycle is a four-stage process that converts heat to work. This method was developed by William Rankine and is utilized to produce the majority of the world's energy today. The most common fluid used in this closed cycle is water, but other fluids are also used. The four stages in the system are as follows: (1) compression (or pressure

increase), (2) heating, (3) expansion, and (4) condensation cooling. In the initial stage, the working fluid's pressure is increased from low to high pressure through use of a pump. The fluid is then sent to a boiler where it is heated at a constant pressure by an external source becoming a vapor. The pressurized heated vapor is allowed to expand through a turbine to low-pressure creating usable power (e.g., electricity). The final stage condenses the working fluid (i.e., the vapor) back to liquid to be sent back to compression.

Spark ignition. In an internal combustion engines the fuel air mixture in the combustion chamber is ignited utilizing a spark from a spark plug. This method is in contrast to compression ignition.

Sustainable. At the core, sustainable implies allowing one generation to meet its needs without depriving future generations of meetings their needs. Sustainable also means that the process will not contribute to dramatic lifestyle changes required of future generations. The Merriam-Webster online dictionary defines *sustainable* as "1: capable of being sustained; 2 a: of, relating to, or being a method of harvesting or using a resource so that the resource is not depleted or permanently damaged <sustainable techniques> <sustainable agriculture> b: of or relating to a lifestyle involving the use of sustainable methods <sustainable society>." In engineering terms, sustainable means that the process can continue indefinitely with the proper operation and maintenance, and that the economics show a good rate of return for the facility's investment. Sustainable also means that plant emissions are minimized with best-available control technology, and that for CHP systems the plant meets a minimum 70 percent prime fuel utilization factor (author's definition). On a general basis, sustainability involves: cleaning up and reusing existing sites and facilities (protecting ecosystems by using "brown field" versus "green field"), reusing construction materials and/or recycled construction materials and/or sustainable materials (minimize resource depletion), minimizing construction waste and equipment pollution, minimizing facility water usage, minimizing facility waste streams and pollution, maximizing indoor environmental quality (which increases human productivity), and minimizing overall facility energy usage.

System-level diagnostics. Even if individual systems are operating properly, the system as a whole may not be operating optimally. Therefore, there is a need for diagnostic algorithms that monitor whole-system performance on a continuous basis and detect and diagnose faulty and degraded operation.

Thermal efficiency. Thermal efficiency is equal to the amount of heat out of boiler or combustion device divided by the fuel input in consistent units, times 100 percent.

Thermal-electric ratio. Each engine type as well as each specific engine has its own heat output versus electric output. For example, some prime movers produce much more heat per unit of electricity than other prime movers.

Topping-cycle. A topping-cycle produces electric power as the main product with heat recovery as the secondary product. Topping-cycles are the most coming type of CHP arrangement today.

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