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COMBINED HEAT AND POWER SYSTEMS ANALYSIS FOR CALIFORNIA

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PREFACE

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Combined Heat and Power Systems Analysis for California is the final report for the Combined Heat and Power Systems Analysis for California project (contract number 500 - 11 - 002, conducted by the Pacific Region Clean Energy Application Center, UC Berkeley, and UC Irvine. The information from this project contributes to Energy Research and Development Division's Energy Systems Integration Program.

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ABSTRACT

This assessment reviews the current market environment for combined heat and power (CHP) in California, the market impact of the latest evolution of the California Self-Generation Incentive Program, and the potential for CHP in several types of California buildings based on detailed building energy data collection and analysis. The analysis involves both market-level and site-level analysis of system economics based on optimization modeling results for both "cost minimization" and "greenhouse gas minimization" scenarios. The building energy use analysis relies on extensive collection of 15-minute interval data of building electrical and thermal loads for example building types in California. Key findings include that the constraints imposed by the performance-based character of the latest version of the incentive program, along with extensive program metering and data reporting requirements, appear to be limiting the desired ability of the incentive program to stimulate CHP demand in California. The detailed economic modeling results suggest that CHP operational strategies may in some cases benefit from excluding the incentive by having more operational flexibility, compared with accepting the incentive and having to follow the program rules. This suggests that a re-examination of the California incentive program design details may be warranted for ways to improve its effectiveness given current market realities.

Keywords: combined heat and power, distributed generation, district energy, energy policy, building energy analysis, incentive

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EXECUTIVE SUMMARY

Introduction

The purpose of this report is to examine key issues related to further implementation of combined heat and power (CHP), waste heat to power, and district energy systems in California. Specific issues addressed include the current status of installed CHP in California, recent target-market outreach efforts to promote CHP, the current status and effectiveness of the California Self-Generation Incentive Program (SGIP), and attractiveness and potential sizing of CHP in California for key target market sectors based on detailed building-energy use analysis.

This report has been prepared by the United States Department of Energy (DOE) Pacific Region Clean Energy Application Center (PCEAC) under funding provided by the California Energy Commission ("Energy Commission"). The PCEAC is a U.S. DOE and California Energy Commission sponsored center to provide education and outreach assistance for CHP, district energy, and waste heat-to-power in the Pacific region of California, Nevada, and Hawaii. The PCEAC was in operation from 2009-2013, led by the University of California (Berkeley and Irvine campuses) and associated partner groups.

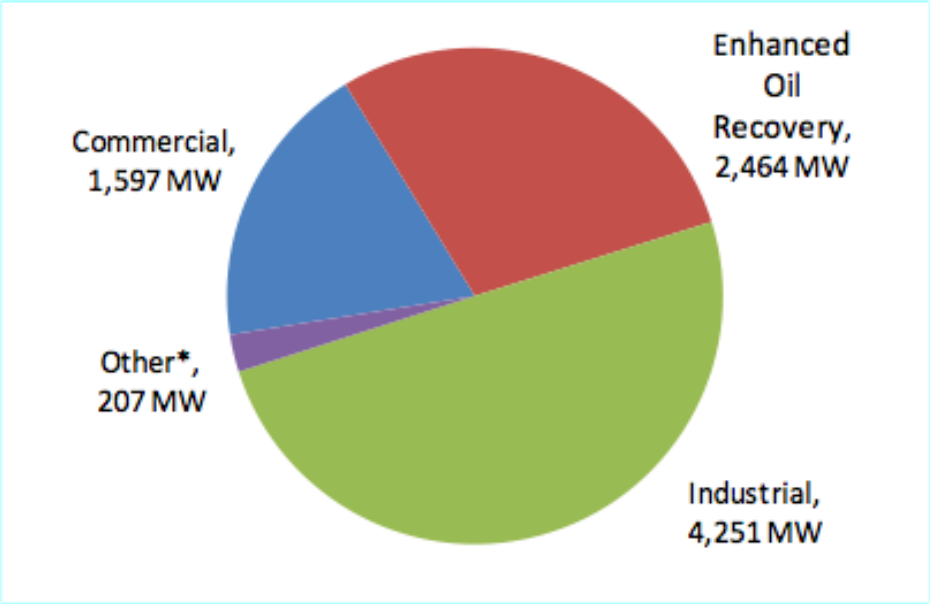
The information presented in this report is intended to provide:

- An overview of CHP installations in California;
- A summary of recent outreach efforts to promote CHP in key sectors;
- An assessment of the impact of the present and potential future SGIP on system economics;
- An analysis of building energy use by type in California settings, for a few key building types;
- An assessment of CHP potential for the building types analyzed in detail; and
- Recommendations and conclusions.

The California CHP Installed Base

The Pacific region has over 1,300 CHP installations at present, with most located in California and in a wide range of industrial and commercial applications. The latest version of the Energy and Environmental Analysis Inc./ICF International (EEA/ICF) database of CHP installations in the state shows a total of 1,272 sites. Figure ES-1, below, presents the breakdown of active CHP systems in California by application. As shown in the figure, about half of California's CHP is industrial in nature, with major contributions as well from enhance oil recovery and the commercial sector.

Figure ES-1: Total CHP Systems in CA by Application[1]



Key Project Findings

In general, the market for CHP in California remains interesting and with potential, but with many nuances and complexities described in this paper and other recent reports[2][3][4]. The key findings from the study with regard to the specific subject areas examined are summarized below.

California's Installed CHP Base and Further Market Development

- Recent PCEAC efforts to promote exploration of CHP in key market sectors in California believed to have significant remaining potential, including the hospital/health care sector and the Wastewater Treatment Plant (WWTP) sector, showed significant interest and follow-up activities. These were related to CHP sector webinars held by the PCEAC in Spring/Summer 2013.

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[1] Hedman, B., K. Darrow, E. Wong, and A. Hampson, ICF International, Inc. *Combined Heat and Power: 2011-2030 Market Assessment.* CEC-200-2012-002, Sacramento: California Energy Commission, 2012. (http://www.energy.ca.gov/2008publications/CEC - 200 - 2008 - 002/CEC - 200 - 2008 - 002.PDF)

[2] Hedman, B., K. Darrow, E. Wong, and A. Hampson, ICF International, Inc. *Combined Heat and Power: 2011-2030 Market Assessment.* CEC-200-2012-002, Sacramento: California Energy Commission, 2012. (http://www.energy.ca.gov/2008publications/CEC - 200 - 2008 - 002/CEC - 200 - 2008 - 002.PDF)

[3] Neff , Bryan, *A New Generation of Combined Heat and Power: Policy Planning for 2030*, California Energy Commission, CEC-200-2012-005, 2012.

[4] Stadler, M., M. Groissböck, G. Cardoso, A. Müller, and J. Lai, "*Encouraging Combined Heat and Power in California Buildings*," Berkeley Lab Environmental Energy Technologies Division, LBNL-6267E, 2013.

- California's CHP installation database currently lists over 1,200 CHP sites in California, but many of these are aging facilities with uncertain futures. Efforts by the PCEAC to assist ICF International to update the California database revealed many sites that are no longer in operation, that have either been removed from the database or put in an "idled" mode as appropriate.
- Recent policy developments such as "must take" rules for CHP enacted by the California Independent System Operator (CAISO) suggest that the state recognizes the potential benefits of maintaining and expanding CHP in California.

Analysis of the Economic Impacts of SGIP

- Broad analysis of potential power market trends associated with potential imposition of some level of carbon pricing shows increasing additions of renewable and natural gas power and lower levels of coal power investment. It is unclear, however, how much of this natural-gas based generation might be distributed CHP compared with larger combined-cycle power plants.
- California market-level analysis of CHP implementation related to the availability of the SGIP program shows only a small impact of the program, assuming current natural gas and electricity prices in California markets. This analysis was conducted by LBNL with assistance from PCEAC, using the DER-CAM distributed energy resource adoption model.
- However, in the presence of a natural gas "price adder" associated with the implementation of California's cap and trade program (for 2015 and beyond), CHP economics relative to a conventional case baseline do improve and CHP investments that were "borderline" become clearly economically advantageous.
- Actual applications for SGIP funding for "Level 3 – Non Renewable" projects have been limited since the program rules were broadened in 2011 to re-admit combustion-based CHP, perhaps related to the reasons described in this study.

Building Energy Analysis

- The UCI measured and CEUS data are in reasonably close agreement. The Southern California location and perhaps narrower focus (in the case of health and hospital sector) are reasons for the deviation in energy values.
- There is a seasonal variation in energy intensity but perhaps as a result of Southern California Centric locations, not too wide a variation.
- Temporal variations in measured energy intensity is critical for understanding energy needs for any sector that is not captured with an "average" intensity.
- Based strictly upon heat energy versus electric energy intensities, DG/CHP would seemingly be fuel cell and reciprocating engine centric. However, a significant shift in the heat to electric ratio would occur if the available waste heat were utilized for thermal

activated cooling (e.g. absorption chilling); the displaced chiller electric load and the increase in thermal need would shift the heat to electric ratio towards gas turbine systems (as is the case for the UC Davis Medical Center).

- Modeling of facilities for energy needs with minimal information (e.g. utilizing eQuest Wizard) can be very misleading. Models can be refined with some additional building specifics to better match. However, a good understanding/assessment of building needs and energy profiles is vital as models tend to underestimate loads and cannot capture the specifics of a particular facility without this information.
- Application/sizing of CHP systems to date, with some notable exceptions, has been one perhaps best described as a supplement "peak shaving" system to existing building services and needs. Very few facilities have developed/implemented systems that meet all of their needs, both electrically and thermally. When used in the supplementary role, the non-critical nature of the systems tends to result in reduced operation and more importantly reduced attention/service/maintenance (i.e. easy to forget that inevitably results in reduced efficiency and impact on the facility. Conversely, where a facility has interest in the system, especially when the CHP system provides the majority (or all) of the facilities electric and thermal needs, there is a strong commitment on the part of the facility to maintain and service the CHP equipment to insure strong and reliable performance.

Policy Recommendations

Based on the findings described above, particularly related to the analysis of the implementation effectiveness of SGIP, Here are the recommendations:

1) First, the design of the SGIP should be re-evaluated based on the relatively low level of applications over the past few years for the Non-Renewable part of the program.
2) Second, perform additional CHP market analyses to understand the key factors inhibiting CHP uptake, such as the imposition of utility standby and demand charges. Recent analysis has shown that these do have an important impact[5], where a relaxation of standby/demand charges could significantly expand CHP uptake. The authors believe that some level of standby charges are appropriate but need to be carefully considered along with the potential grid congestion relief and other benefits that CHP systems can provide.
3) Third, there is a relatively poor understanding among potential CHP "end user" groups (that may adopt additional CHP systems in California) of the latest utility interconnection, SGIP, and feed-in tariff program rules, as well as the agreements made by utilities and the CAISO to prioritize the procurement of CHP-based generation.

[5] Hedman, B., K. Darrow, E. Wong, and A. Hampson, ICF International, Inc. *Combined Heat and Power: 2011-2030 Market Assessment.* CEC-200-2012-002, Sacramento: California Energy Commission, 2012. (http://www.energy.ca.gov/2008publications/CEC - 200 - 2008 - 002/CEC - 200 - 2008 - 002.PDF)

Further efforts to harmonize and integrate these programs, as well as additional education and outreach efforts to publicize their potential positive impacts on CHP system economics, appear to be clearly needed.

4) Finally, further "stakeholder" summit meetings should be held to garner feedback from industrial groups and CHP vendors, manufacturers, and system integrators to better understand the market challenges facing CHP in California and how they might be best addressed. While much progress has been made to make CHP systems easier to connect and commission, previous feedback from industry groups to the PCEAC has indicated that significantly issues and barriers still remain.

Conclusions

In conclusion, the CHP market in California continues to evolve in complicated ways. The combined impacts of evolving technologies, competing options and fluctuating fuel prices, and a complex and intricate policy and market environment creates a somewhat challenging environment for those in a position to adopt further CHP in the state. This study has indicated that different market segments in California have significant difference in terms of their basic energy use patterns that impact potential CHP system design and implementation. Identifying successful models for CHP adoption for specific market segments, through more careful study and further implementation experience with the latest technologies, could help to further develop these markets through the accumulation of "lessons learned" and development of best practices for system implementation and operation.

CHAPTER 1: Introduction

1.1 Project Background

Combined heat and power (CHP) is defined as "the sequential production of electric and thermal power from a single dedicated fuel source[6]." The benefits of CHP vary on a site-specific basis, but can include energy efficiency, energy cost, power reliability, utility grid support, and greenhouse gas (GHG) reduction and other environmental benefits. These depend not only on the conditions of the CHP "host" site but also on the characteristics of the larger utility grid and power supply system in the region.

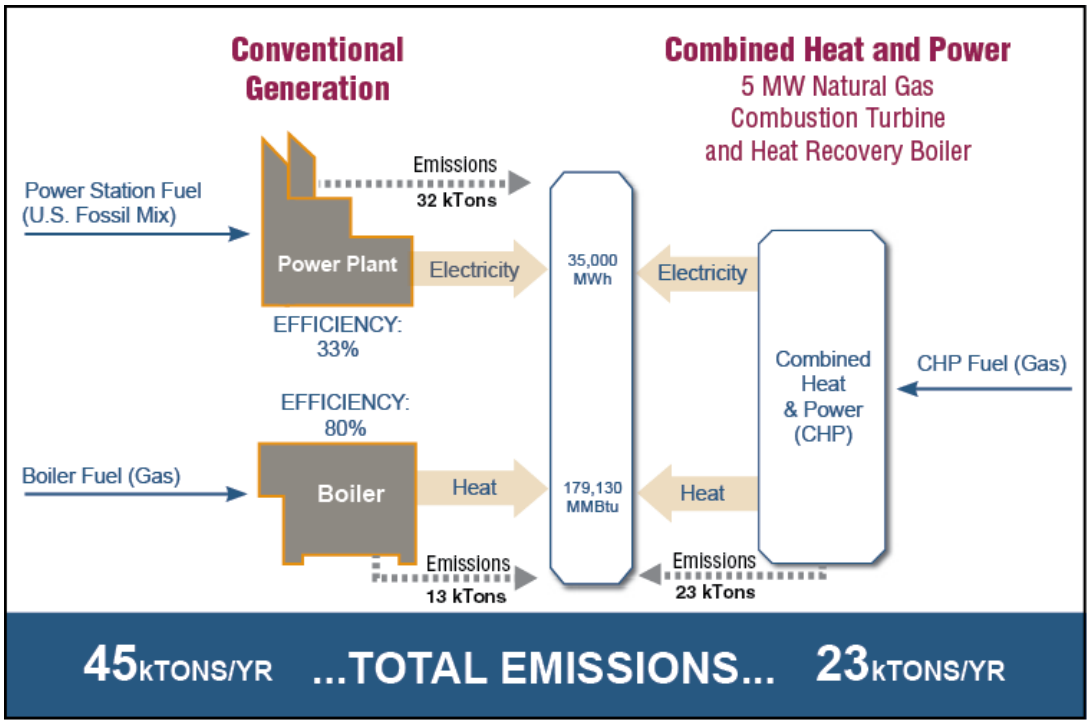
Additional concepts include "waste heat to power" (WHP) and "district energy." WHP is defined as a system that "captures heat otherwise wasted in an industrial process and utilizes it to produce electric power." These systems may or may not produce additional thermal energy as well. District energy is defined as "central heating and cooling plants that incorporate electricity generation along with thermal distribution piping networks for multiple buildings (e.g. campus /downtown areas)[7]."

As shown in Figure 1-1, below, CHP can provide the same overall electrical and thermal benefits to a host site with much lower energy inputs, and correspondingly lower emissions of greenhouse gases. In this example, total site emissions of carbon dioxide (CO2) are reduced from 45,000 tons per year with conventional generation strategies to 23,000 tons per year with the use of a 5 MW CHP system. In-use CHP system efficiency varies by site and the co-incidence of electrical and thermal loads, but can often be in the 65-80 percent range in terms of overall thermal efficiency with waste heat capture (see Appendices for details on CHP performance metrics).

[6] Olsen, Brian, "Combined Heat and Power and District Energy - Endless Possibilities," U.S. Department of Energy, Technical Assistance Program, Energy Efficiency and Renewable Energy, November 10, 2010.

[7] Olsen, 2010.

Figure 1-1: CHP Energy Efficiency and Emissions Benefits



Source: http://www.epa.gov/chp/basic/environmental.html

There is a long history of CHP installations in California, particularly starting in the 1980s after the passage of the Public Utility Regulatory Policies Act (PURPA) in 1978, which allowed for a broader array of generation types to provide power to utility grids if they could meet or beat the local utilities "avoided cost" of generation. These new power generation types included distributed generation sources such as CHP and small-scale renewable power systems. A national CHP database now lists 1,272 operational CHP systems in California, totaling nearly 8.8 GW of capacity[8]. As shown later in this chapter, these installations span a wide range of applications, CHP system types, and system sizes.

[8] See: http://www.eea-inc.com/chpdata/States/CA.html

Table 1-1: CHP Installation Summary for California

Prime Mover Technology	Sites	Capacity (kW)
Boiler/Steam Turbine	42	987,420
Combined Cycle	47	3,328,965
Combustion Turbine	149	3,790,294
Fuel Cell	78	44,255
Microturbine	187	34,293
Other	8	2,803
Reciprocating Engine	757	550,074
Waste Heat to Power	4	18,667
Total	1,272	8,756,771

Source: EEA/ICF CHP Database: http://www.eea-inc.com/chpdata/index.html.

This report has been prepared by the United States (U.S.) Department of Energy (DOE) Pacific Region Clean Energy Application Center (Pacific CEAC) under funding provided by the California Energy Commission ("Energy Commission"). The Pacific CEAC is a U.S. DOE and Energy Commission-sponsored center to provide education and outreach, policy analysis, and direct project assistance for CHP, district energy, and waste heat-to-power in the Pacific region of California, Nevada, and Hawaii. The Pacific CEAC is operated by the University of California – Berkeley (UCB), the University of California – Irvine (UCI), San Diego State University (SDSU), and San Francisco State University (SFSU).

1.2 Report Organization

This report is organized as follows. Chapter 1 reviews the basic types current status of CHP technologies, the installed base of CHP in California, and recent PCEAC efforts to update the database. Chapter 2 discusses recent effort to promote the implementation of key market sectors for CHP in California. Next, Chapter 3 examines the current and potential future impacts of the California Self-Generation Incentive Program (SGIP) on the California CHP market. Then, Chapter 4 presents key building energy-use data collected from several buildings in California. Chapter 5 provides additional modeling and analysis of building energy loads and examines potential CHP system sizing. Finally, Chapter 6 presents overall study findings and conclusions.

The appendices include: A) CHP technology characterizations and performance forecasts; B) additional details about the DER-CAM modeling discussed in Chapter 3; and C) (Appendix C if added).

1.3 Current State of CHP Technologies

CHP technologies have evolved considerably over recent years, expanding beyond traditional combustion engines (also known as "reciprocating engines") and industrial gas turbines to now also include microturbines and fuel cells as well as WHP options including Rankine-cycle devices and others. The various types of CHP systems have different capital and maintenance costs, different fuel costs based on fuel type (e.g. natural gas, landfill gas, etc.) and efficiency levels.

The main types of CHP system "prime mover" technologies are reciprocating engines, industrial gas turbines, microturbines, and fuel cells. The more efficient systems (in terms of electrical efficiency) tend to have higher capital costs. Table 1-2 below presents key characteristics of each of these types of generators.

Table 1-2: CHP "Prime Mover" Technology Characteristics

	Microturbines	Reciprocating Engines	Industrial Turbines	Stirling Engines	Fuel Cells
Size Range	20-500 kW	5 kW – 7 MW	500 kW – 25 MW	<1 kW – 25 kW	1 kW – 10 MW
Fuel Type	NG, H, P, D, BD, LG	NG, D, LG, DG	NG, LF	NG plus others	NG, LG, DG, P, H
Electrical Efficiency	20-30% (recup.)	25-45%	20-45%	12-20%	25-60%
Overall Thermal Efficiency (typical LHV values)	Up to approx. 85%	Up to approx. 75%	Up to approx. 75%	Up to approx. 75%	Up to approx. 90%
Emissions	Low (<9-50 ppm) NOx	Controls required for NOx and CO	Low when controlled	Potential for very low emissions	Nearly zero
Primary cogeneration	50-80° C. water	Steam	Steam	Hot water	Hot water or steam (tech. dep.)
Commercial Status	Small volume production	Widely Available	Widely Available	Small production volume	Small volume production or pre-commercial (tech. dep.)
Capital Cost	$700-1,100/kW	$300-900/kW	$300-1,000/kW	$2,000+/kW	$4,000+/kW
O&M Cost	$0.005-0.016/kWh	$0.005-0.015/kWh	$0.003-0.008/kWh	$0.007-0.015/kWh	$0.005-0.01/kWh
Maintenance Interval	5,000-8,000 hrs	ID	40,000 hours	ID	ID

Source: Lipman et al., 2011[9]. Sentech Inc., 2010[10].
Notes:
ID = insufficient data
For Fuel Type: NG = natural gas; H = hydrogen; P = propane; D = diesel, LF = various liquid fuels; LG = landfill gas; DG = digester gas; BD = biodiesel.

[9] Lipman, T., V. McDonell, A. Beyene, D. Kammen, and S. Samuelsen, "Combined Heat and Power Baseline Analysis and Action Plan for the California Market," Prepared for the U.S. Department of Energy and the California Energy Commission, June 30, 2011

[10] Sentech, Inc. (2010), Commercial and Industrial CHP Technology Cost and Performance Data Analysis for EIA, June.

1.4 Overall Project Goals

The purpose of this report is to document CHP-related research and analysis tasks conducted by UCB and UCI for the Energy Commission. These tasks include those to:

1) update the CHP installation database for California;
2) examine the impact of the latest version of the California Self-Generation Incentive Program (SGIP) on California market development and individual site economics;
3) work with state agencies on workshops to further develop and refine CHP, WHP, and district energy related energy and environmental policy in California; and
4) analyze building energy use patterns for the best types of locations for various types/sizes of CHP in California.

These efforts build upon previous activities by the PCEAC including information dissemination through an extensive website, conducting CHP workshops and webinars, providing information and direct project assistance to potential projects, and responding to stakeholder inquiries for information and assistance.

The project task activities are directed to helping to achieve the following goals:

1) improving the understanding of the installed level of CHP capacity in the state;
2) showing the potential impacts of the latest "performance-based" SGIP program;
3) performing building energy-use/load analysis with an eye toward promising sites for CHP to inform the potential applicability to key building types in California; and
4) more generally furthering CHP market develop and providing information for specific installations of CHP in California.

These efforts are intended to help support state policies that have identified a key role for CHP in both energy planning and economic development through 2030[11][12].

1.5 Overview of CHP Installations in California

The Pacific region has over 1,300 CHP installations at present, with most located in California and in a wide range of industrial and commercial applications. The latest version of the Energy and Environmental Analysis Inc./ICF International (EEA/ICF) database of CHP installations in the state shows a total of 1,272 sites. This total may not be exactly correct because some of the older installations in the database may not be currently operational, and because the database is

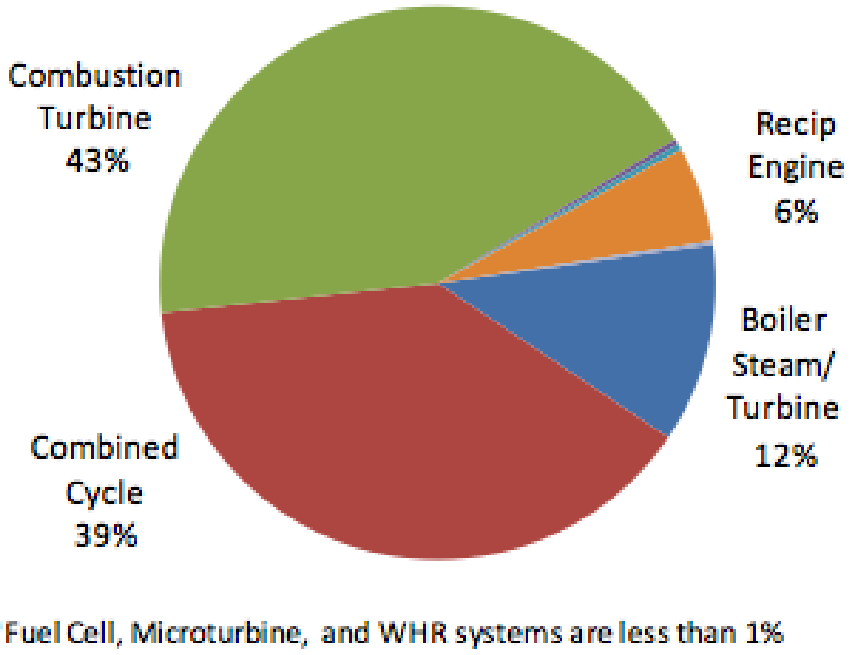
[11] California Energy Commission, 2011 Integrated Energy Policy Report, CEC-100-2011-001-CMF, February 15, 2012.

[12] Neff , Bryan, A New Generation of Combined Heat and Power: Policy Planning for 2030, California Energy Commission, CEC-200-2012-005, 2012.

not comprehensive with regard to new installations. PCEAC is working with EEA/ICF to update the database and improve its accuracy.

Figure 1-2, below, presents the composition of active CHP systems in California by generator type. As shown in the figure, most CHP in California is turbine based, with 43 percent in combustion turbine applications, and another 39 percent in combined cycle configurations. Reciprocating engines make up 6 percent of system capacity, with steam-turbine systems adding the remaining 12 percent of total capacity[13].

Figure 1-2: CHP Systems in CA by Generator Type

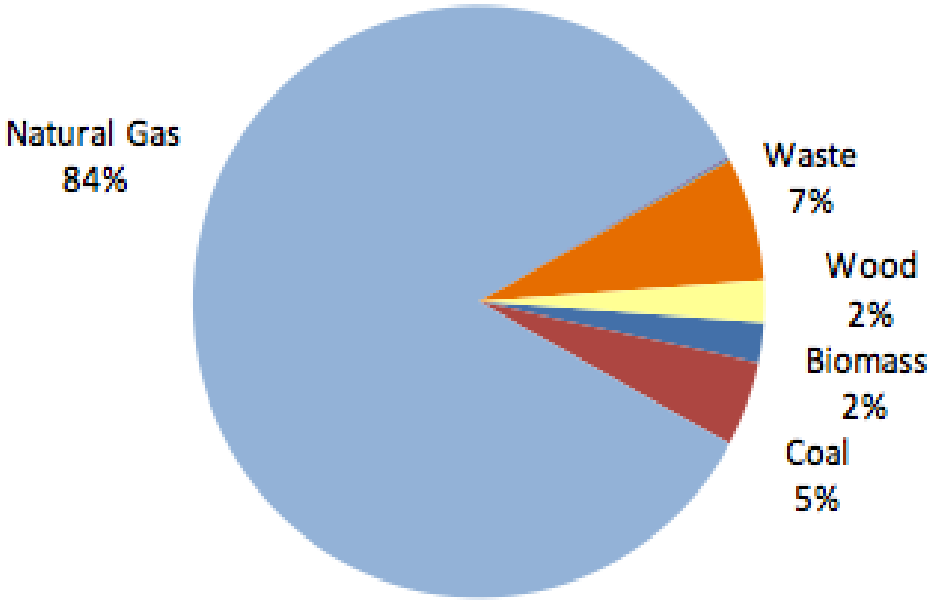


Source: Hedman et al., 2012.

[13] Hedman, B., K. Darrow, E. Wong, and A. Hampson, Combined Heat and Power: 2011-2030 Market Assessment, California Energy Commission, ICF International, Inc, CEC-200-2012-002-REV, June, 2012.

Figure 1-3, below, presents the composition of active CHP systems in California by fuel source. The vast majority of CHP in California is natural gas fueled (84 percent) with small contributions from biomass and coal as additional fuels.

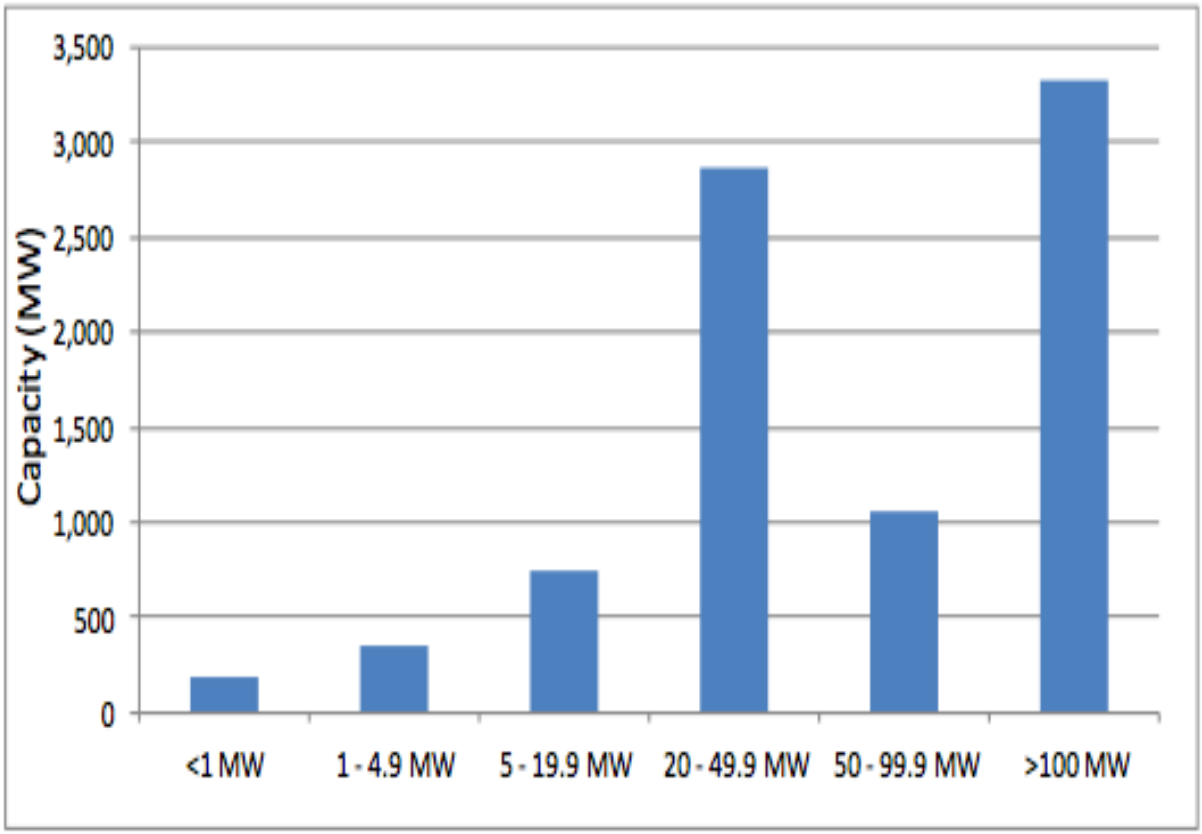
Figure 1-3: CHP Systems in CA by Fuel Source



Source: Hedman et al., 2012.

Figure 1-4, below, presents the composition of active CHP systems in California by system size range. Larger systems of over 100 MW make up the largest share of capacity by system size, with also a very large contribution from the 20-50 MW size class.

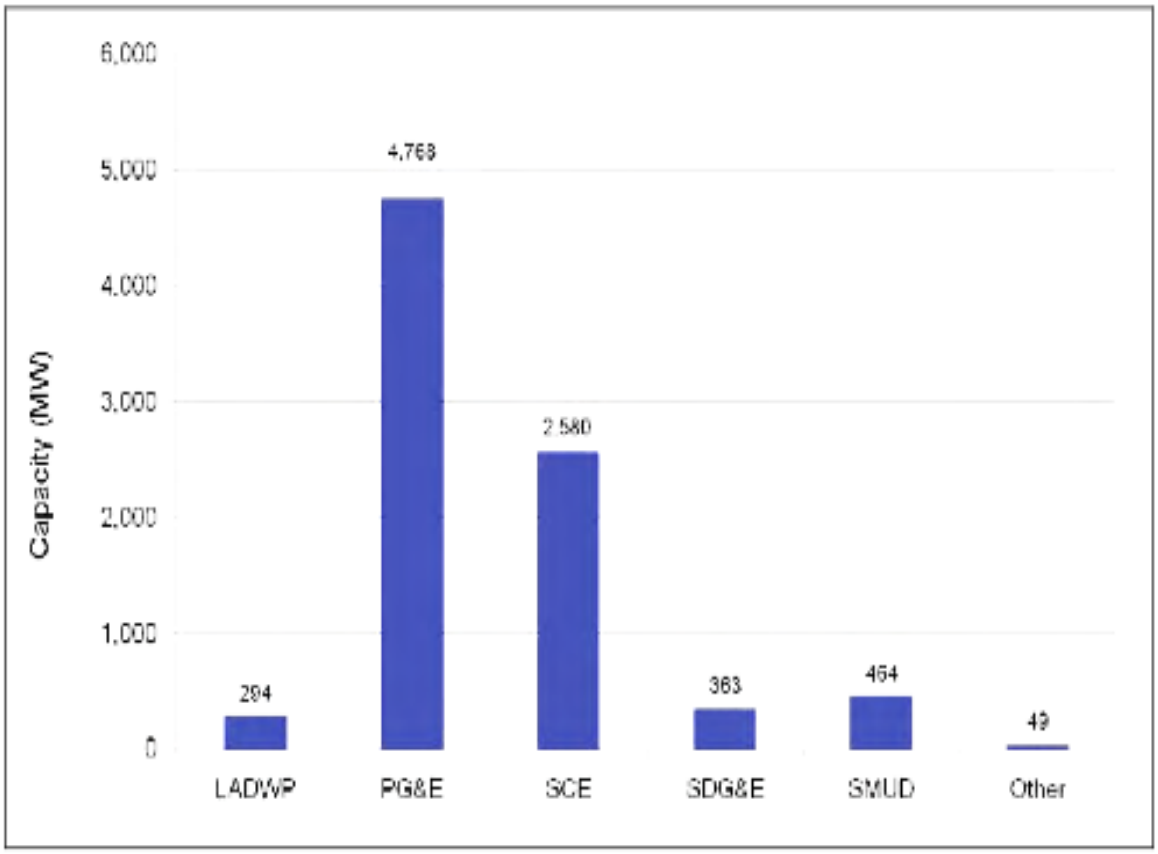
Figure 1-4: CHP Systems in CA by System Size



Source: Hedman et al., 2012.

Figure 1-5, below, presents the composition of active CHP systems in California by utility service territory. Pacific Gas and Electric Company has the most CHP of any utility by a large margin, almost twice as much as the next highest utility of Southern California Edison. San Diego Gas and Electric Company and two large municipal utilities round out the primary utility service territories for CHP in California.

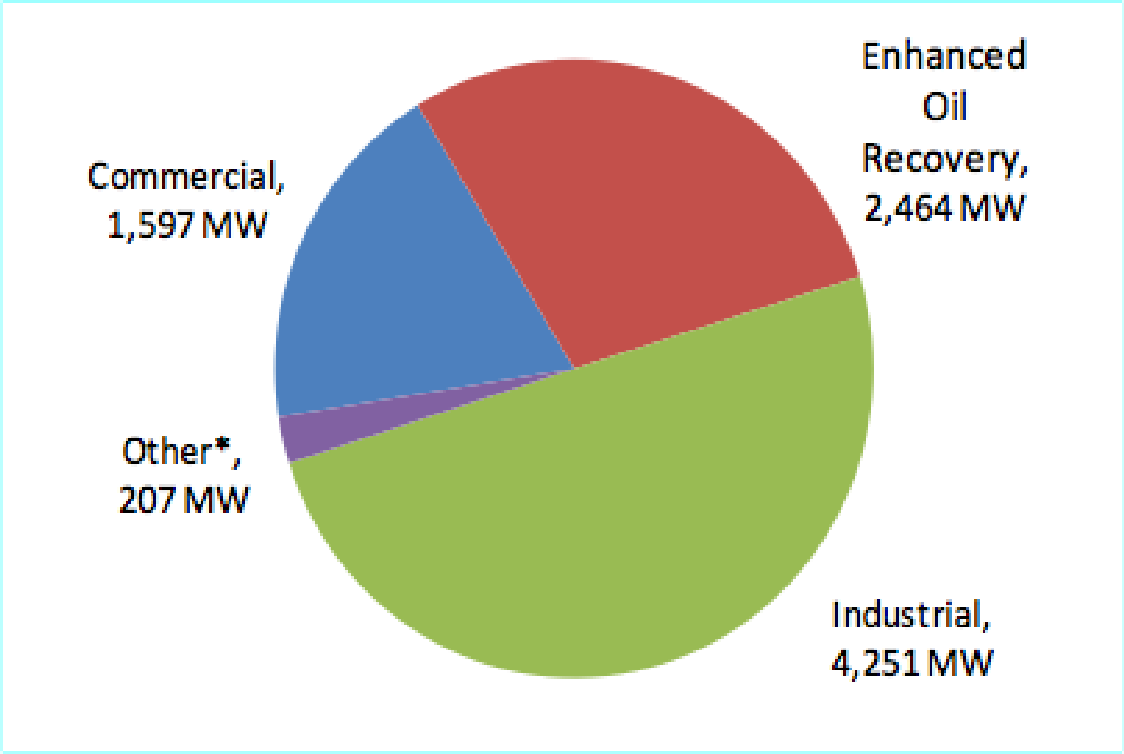
Figure 1-5: CHP Systems in CA by Utility Service Territory



Source: Hedman et al., 2012.

Figure 1-6, below, presents the composition of active CHP systems in California by application. As shown in the figure, about one-quarter of CHP in California is used in the context of enhanced oil recovery operations at refineries. About half of the capacity is associated with other industry, and the other quarter from commercial and other settings.

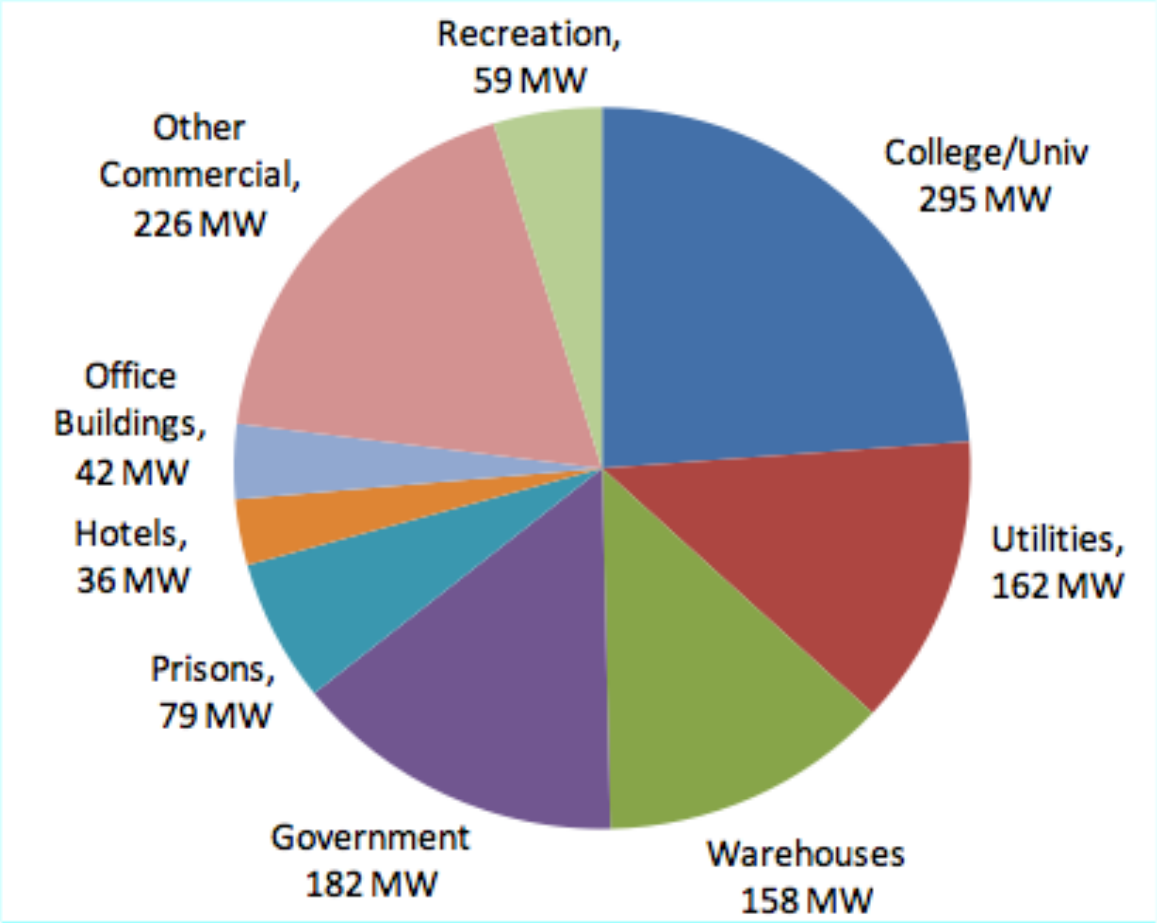
Figure 1-6: Total CHP Systems in CA by Application



Source: Hedman et al., 2012.

Figure 1-7, below, presents the composition of commercial sector CHP systems in California by individual sector. There are several diverse applications in the commercial sector with about a quarter of the system capacity associated with colleges and universities, the utility, government, and warehouse sector accounting for about 10 percent of the capacity each, and the remainder being hotels, office buildings, jails/prisons, and other commercial settings such as breweries and recreational facilities.

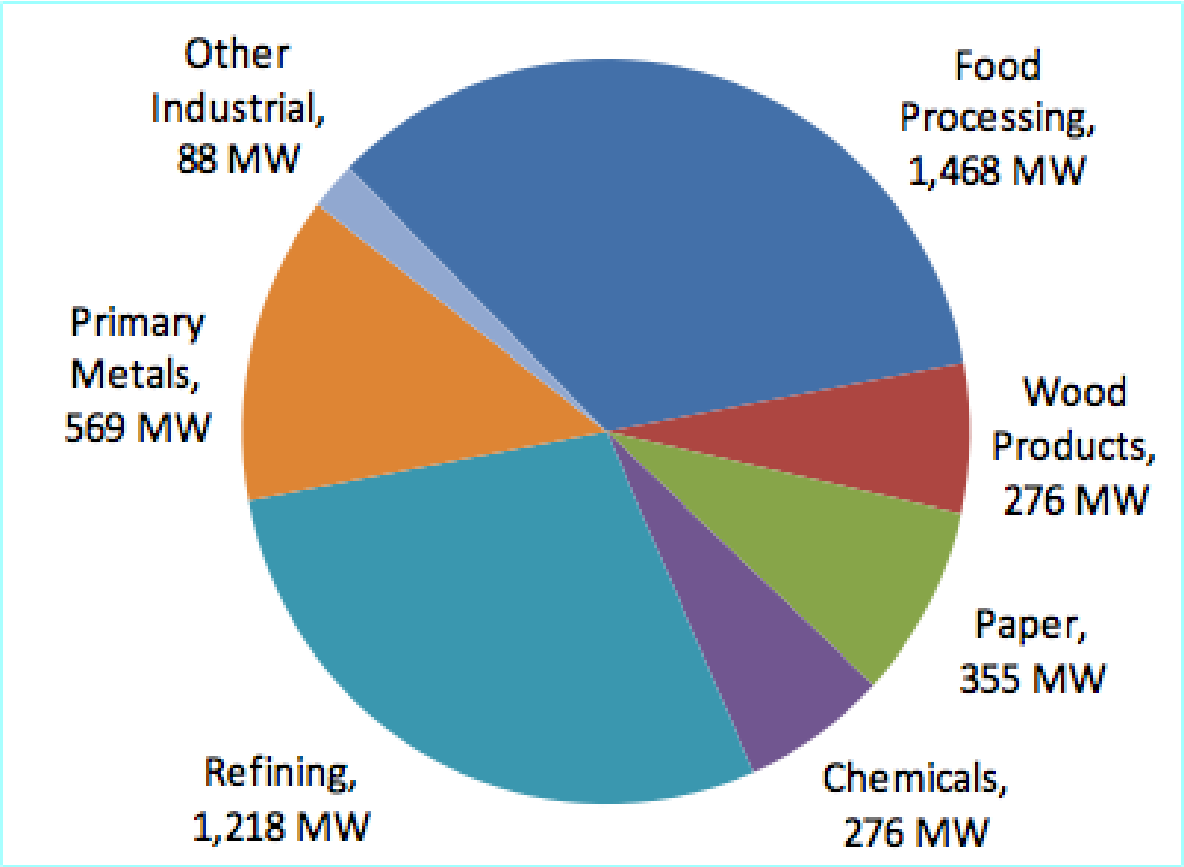
Figure 1-7: Commercial Sector CHP Systems in CA by Application



Source: Hedman et al., 2012.

Figure 1-8, below, presents the composition of industrial sector CHP systems in California by individual sector. Interestingly, food processing makes up the largest sector for industrial CHP, ahead of refinery operations, each comprising about one-third of commercial CHP in the state. Metals, wood and paper, and chemicals, and other sources round out the main industrial sites.

Figure 1-8: Industrial Sector CHP Systems in CA by Application



Source: Hedman et al., 2012.

1.5.1 California CHP Database Update

Working closely with U.S. DOE and ICF International, the PCEAC has made periodic updates to the California CHP database. These updates were made based on a combination of methods for data collection:

- direct inquiries by PCEAC staff about CHP/WHP system operation and continued use;
- information collected from project developers about new CHP and WHP installations;
- information collected by PCEAC from project that received PCEAC technical assistance and/or full project screenings; and
- additional information supplied by PCEAC advisory board members and other individuals about new CHP systems going online or older systems that have been either temporarily idled or permanently decommissioned.

A major update to the database was supplied to ICF International in September 2012, and additional updates have been provided on an ongoing basis through summer of 2013.

The current CHP database lists thirty-six CHP sites that became operational in California in 2012, several with assistance from the PCEAC. These sites totaled approximately 150 MW and had a "prime mover" mix of fuel cells (13 sites), microturbines (8 sites), reciprocating engines (6 sites), gas turbines (4 sites), and boiler/steam turbine (2 sites), with one combined cycle system and two unknown.

CHAPTER 2:
Targeted Outreach Efforts to Build Key CHP Markets in California

2.1 Introduction

The Pacific CEAC has worked since 2009 to foster CHP, district energy, and WHP market development in the Pacific region including California. These efforts have primarily been sponsored by the U.S. DOE but have been enhanced by additional CEC funding.

In particular, CEC funding has assisted with the planning and execution of two key webinars to provide information to CHP market sector end-users in California. These webinars were planned and conducted on specific dates in 2013 but with recordings made for future use. The webinars were:

- April 4th, 2013: "Energy Security and Cost Savings with Combined Heat and Power: Focus on Hospital Applications"
- June 25th, 2013: "CHP for California Wastewater Treatment Plant Sector"

As described below, these webinars were well attended and led to various follow-up requests for information and technical assistance from the Pacific CEAC. Website archival materials are available at: (archive website).

2.2 Summary of California Hospital Sector Webinar

The "CHP for the California Hospital Sector" webinar was held on April 4th, 2013. Key participants included Dr. Timothy Lipman and Dr. Vincent McDonell from the Pacific CEAC as well as the additional participants listed below. A total of 121 participants attended the webinar, including 22 energy "end-user" groups.

<u>April 4th, 2013 Workshop Agenda: Energy Security and Cost Savings with Combined Heat and Power: Focus on Hospital Applications</u>:

10:00 Welcome and Introduction (Tim Lipman, Pacific CEAC)

10:15 Overview of the U.S. DOE Pacific Clean Energy Application Center (Lipman/McDonell, Pacific CEAC)

10:30 Combined Heat and Power (CHP) Opportunities for Healthcare Facilities (Haefke/McDonell, MW and Pacific CEACs)

10:45 End User Perspective Panel

Purecell System at St. Helena Hospital (Hildreth)

Long Island Home (Chester)

11:15 Review of Current Incentives Programs (Tim Lipman, Pacific CEAC)

11:30 Q&A and Discussion

11:45 Wrap Up/Next Steps (Panelists, Pacific CEAC)

12:15 Conclude

Pursuant to the workshop/webinar, presentation materials were posted on the PCEAC website along with a recording of the webinar for future viewing. The PCEAC team received various follow-up requests for information as a result of the workshop. The team also reached out directly to hospital group end-users who participated in the webinar with regard to what needs they had for additional information with regard to their interest in pursuing CHP opportunities at their facilities.

2.3 Summary of California Wastewater Treatment Plant Sector Webinar

The "CHP for the California Hospital Sector" webinar was held on June 25th, 2013. Key participants included Dr. Timothy Lipman and Dr. Vincent McDonell from the Pacific CEAC as well as the additional participants listed below. A total of 211 participants attended the webinar, including 35 energy "end-user" groups.

July 25th, 2013 Workshop Agenda: CHP for Wastewater Treatment Plant Applications:

10:00 Welcome and Introduction (Tim Lipman, Pacific CEAC)

10:15 Why WWTF are a good fit for CHP (McDonell, Pacific CEAC)

10:45 End User Perspective Panel

Eastern Municipal Water District (Erik Jorgensen)

East Bay Municipal Utility District (John Hake)

Orange County Sanitation District (Jim Mullins)

11:45 Review of Current Incentives Programs (Tim Lipman, Pacific CEAC)

12:15 Wrap Up/Next Steps (Panelists, Pacific CEAC)

12:30 Conclude

Following the workshop/webinar, presentation materials were posted on the PCEAC website along with a recording of the webinar for future viewing. The PCEAC team received various follow-up requests for information as a result of the workshop. The team also reached out directly to hospital group end-users who participated in the webinar with regard to what needs they had for additional information with regard to their interest in pursuing CHP opportunities at their facilities

CHAPTER 3:
Impacts of California SGIP Program on CHP Project Economics

3.1 Introduction

The purpose of this chapter is to examine the current and potential future impacts of the SGIP in California. The impacts are assessed at both the individual project and larger market levels. The SGIP has been modified in recent years to adopt a "performance based" nature, with incentives directed to initial project costs but paid out over 5 years instead of in a single upfront payment (for systems over 30 kW). The SGIP also includes additional metering, monitoring, and reporting requirements, with additional analysis of those impacts on system costs included in the report Appendix C.

3.2 The California SGIP Program

The California Self-Generation Incentive Program (SGIP) was created in 2001 as one of many measures sought by the California Legislature to respond to statewide electrical shortages in 2000 and 2001. The program endeavored to reduce peak system loads and to incentivize new emerging technologies. Over the past ten years the SGIP, overseen by the California Public Utilities Commission (CPUC), has provided capital-cost buy-down incentives for distributed generation (DG) projects in California investor-owned utility service territories.

There have been several refinements to the program since 2001, including eligible technologies, incentive rates, and program budgets. The key changes include:

- From 2001–2007, SGIP supported fossil-fuel systems, as well as renewable energy systems, provided that they could meet the emission standards of California's Air Resources Board (CARB);
- Initially, solar photovoltaic (PV) systems were included in the SGIP along with wind power and combined heat and power (CHP) systems;
- However, in 2007, solar PV systems were moved to the California Solar Initiative (CSI), an incentive program dedicated to solar PV systems, solar-thermal energy systems, and solar power research, development, and demonstration;
- In 2008, combustion-based system were excluded from the SGIP, but returned to the program in 2011 in conjunction with an extension of program funding through 2011[14]; and
- Program funding was then subsequently extended from 2011 through 2014 with program administration through 2015[15].

[14] Senate Bill 412 (Kehoe, Chapter 182, Statutes of 2009)

From 2001-2010, 432 CHP systems representing 222 MW of generation capacity were installed under the SGIP. The peak year for system installation was 2005, when 81 systems representing 40 MW of capacity were installed. In comparison, only 23 systems for a total of 9.7 MW were installed in 2010.

3.3 Current SGIP Guidelines and Rules

The SGIP has been modified several times in recent years, with a major revision in 2011. Key new features of the program include a "performance based" character, where the incentive is paid out over 5 years instead of all upfront, and where there are now additional requirements for monitoring and system performance reporting. Appendix C assesses and summarizes the potential additional costs of the SGIP system metering requirements.

The key program guidelines are briefly summarized below. For further details, see the latest SGIP Handbooks provided by the California IOUs[16].

3.4 Eligibility

Eligibility for participation in the SGIP is based on an expectation that the project will provide GHG reductions, measured against a baseline of 349 kg CO2/MWh, adjusted to 379 kg/CO2/MWh to account for avoided transmission and distribution losses. In years that the project does not meet the baseline to within 5 percent (i.e., 398 kg CO2/MWh) its annual incentive payments may be reduced by 50 percent (if it emits less than 417 kg CO2/MWh) or eliminated (if it emits more than 417 kg CO2/MWh). Projects must be within the service territories of the California investor-owned utilities (Pacific Gas and Electric Company, San Diego Gas and Electric Company, Southern California Edison, and Southern California Gas Company).

3.5 System Size

There is no minimum size requirement. Wind power (<50 kW) and renewable fueled fuel cells can also apply for support under the California Energy Commission Emerging Renewables Program. The incentive applies to the first 3 MW of any project, with the following schedule.

0-1 MW = 100%

1-2 MW = 50%

2-3 MW = 25%

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[15] Assembly Bill 1150 (Perez, Statutes of 2011)

[16] California Public Utilities Commission, 2013 Self-Generation Incentive Program Handbook, February 1, 2013.

3.6 Incentive Design – Performance Based

The program includes a performance-based incentive (PBI) structure where 50 percent of the overall payment is offered up front and the remaining amount is paid at 10 percent per year for five years (except for projects under 30 kW that receive the entire amount upfront). However, PBI payments may be reduced or eliminated in relation to a 5 percent exceedance band if expected levels of efficiency and/or GHG reductions levels are not attained.

3.7 Eligible Technologies and Incentive Rates

Table 3-1 shows the SGIP program incentive rates by technology and fuel type. Incentive rates decline 10 percent each successive year through the program sunset in 2016.

Table 3-1: Base SGIP Incentive Rates by CHP/WHP Related Technology Type

Technology	Incentive Level ($/w)
Combustion-based CHP	$0.48
Advanced energy storage	$1.80
Fuel cell (CHP or electricity only)	$2.03
Waste heat to power	$1.19
Pressure reduction turbine	$1.19
Biogas adder	$1.80

Source: SGIP Program Handbook, 2013 Edition.

3.8 Incentive Rate and Limits

Below are the current tiered incentives rates, where there is no incentive offered beyond the first 3 MW of any given project. The percentages are to be applied to the incentive level as depicted in Table 1.

Program incentives are subject to an annual 10 percent decline in incentives for emerging technologies and a lower 5 percent annual reduction for all other technologies, starting in 2013. To ensure diversity, no individual supplier's technology can receive more than 40 percent of program funds in any year. Furthermore, there is a requirement that SGIP participants pay at least 40 percent of eligible project costs.

3.9 Measurement and Evaluation

Metering and monitoring systems are required for projects 30 kW and larger. Specific requirements include:

- Electrical output measurements with frequency of no less than every 15 minutes;
- Electrical output metering accuracy to within (+/-) 2 percent of actual system output, certified by an independent testing body;

- Thermal metering for CHP installations to determine the amount of useful thermal energy recovery and use;
- Thermal metering frequency of no less than every 15 minutes and accuracy to within (+/-) 5 percent of actual output;
- Fuel use metering systems for CHP installations and electric-only fuel cells to determine the amount of system fuel consumption;
- Fuel use metering sampling interval of no less than every 15 minutes in frequency and accuracy to within (+/-) 5 percent of actual fuel use; and
- All electrical and thermal output and fuel use monitoring systems must be capable of storing data in the event of power outages or communication failures.

3.10 Export to the Grid

No more than 25 percent of onsite power can be sold to the grid on an annual basis.

3.11 Energy Efficiency Requirement

Customers are required to submit a summary of the completed audit, identifying which, if any, energy efficiency measures will be taken and how these measures affect sizing of the project. These audits are mandatory unless an extensive audit has been conducted with the five years prior to application.

3.12 Application Fee and Maximum Reservation Hold Time

An application fee is required of 1 percent of the amount of requested incentive funds, with the fee then being refunded upon verification of an installed project or if the project application is halted before a conditional reservation has been obtained.

3.13 Warranty Requirement

3.13.1 SGIP Program Statistics for 2011 through 2013

Since the modification in the SGIP to allow eligibility for combustion-based CHP systems that meet the program criteria, the actual applications for SGIP funds have not risen appreciably. For example, in PG&E service territory, there were only $39,000 in reserved projects in 2011 under the "Level 3 – Non-Renewable" category compared to over $29 million in reserved projects in the "Level 2 – Renewable" category. Consequently, over $15 million in funds allocated to the Level 3 program were re-allocated to the Level 2 program. In 2012, reservations under the Level 3 program had risen to just over $4 million, but compared with over $40 million in the Level 2 program reservations. Again in 2010, $10 million in allocated funds for Level 3 were re-allocated to Level 2. PG&E statistics through September 2013 are currently showing no reservations for Level 3 funding in 2013, compared with $19.6 million in reservations for the Level 2 – Renewable program.

Furthermore, in Southern California Edison/Southern California Gas territory, there was an even lower -– in fact total lack of -- response to the SGIP support program for combustion-based

CHP in 2011-2013. The latest utility reports show no paid projects in the "Level 3 – Non-Renewable" category in 2011, 2012, and through the first half of 2013[17].

These statistics show that even though the SGIP program has been broadened to allow the inclusion of combustion-based CHP systems, few of these systems are actually being proposed for implementation under the SGIP. Perhaps this is a case of "lead time" from project conceptualization to application for SGIP funds, but additional potential hypotheses are explored below relating to key constraints on the SGIP funding.

3.13.2 Market-Wide Assessment of SGIP Impact on CHP Potential

In the context of potential expansion of CHP implementation in California, it is worth briefly discussing overall trends and drivers in the state energy sector. In recent years, the state of California has mandated aggressive renewable portfolio standard (RPS) targets, as well as greenhouse gas (GHG) emissions reduction goals. Concurrently, the Federal Energy Regulatory Commission (FERC) has encouraged the expansion of energy markets that can incentivize increased numbers of market participants, particularly among smaller participants. As a result of these policies, the market environment and economics that govern the adoption of CHP systems is expected to change significantly through 2050. Studies and literature investigating the impacts of current and expected regulatory policy is discussed at the following scales:

- Western Electricity Coordinating Council (WECC): Encompasses the majority of the interconnected electrical grid west of the Mississippi River.
- California ISO (CAISO): California state power "balancing authority" located within the WECC.
- Individual Facilities: CHP investment decisions at sample facilities located within the CAISO.

The market potential developments related to CHP are briefly discussed below, particularly in the context of the California setting, with broad potential market trends for the WECC area discussed first.

[17] Source: https://www.sce.com/wps/wcm/connect/a053abc9-cc87-410d-aa2c-46994c020242/SGIP+Monthly+Report_SCE_Sep2013.pdf?MOD=AJPERES

3.14 WECC Modeling

The WECC is an entity that works with other entities within the western interconnection to coordinate investments in bulk electrical systems, and promote policies and regulations for the increased reliability of the bulk electrical grid. Within the Western Interconnection, all grid-connected entities are synchronized; i.e. all generators spin at the same frequency, and any grid connected generator or consumer can theoretically affect the operation of the entire system.

Interconnected electrical grids, such as the WECC, necessitate that for technical reasons all investment, market operations, and policy decisions in one area of the grid can affect operations and decisions in all other areas. As a result, long-term adoption of CHP will depend on investment and operations decisions within the Entire WECC.

3.14.1 Description of SWITCH Model

To accurately model long-term investment and operations decisions within the WECC, the Renewable and Appropriate Energy Laboratory (RAEL) at UC Berkeley developed the SWITCH model. The SWITCH model is a combined operations-investment optimization model built to determine the most cost-effective investments to meet future electricity demand given various policy scenarios. The model includes grid integration costs of transmission and distribution, capital costs of generating systems, operating costs, capacity factors, and other key variables but arguably does not fully include additional factors such as investment risk. Model inputs are deterministic, and the model determines the capacity investments needed to meet operational requirements[18]. Beyond capacity and reserve margins, the driving constraints of the optimization are RPS goals and GHG emissions reduction targets within the WECC.

The model output details the needed transmission and generation capacity additions for each load area within the WECC to meet increased demand, RPS targets, and GHG emissions reduction targets. While the model does not specifically include CHP, it does include combined cycle gas turbines, and natural gas fired turbines in the optimization. CCGT facilities have GHG emissions intensities close to those of CHP facilities (Heath et al. 2006; Strachan and Farrell 2006) when avoided boiler emissions for CHP facilities are accounted for. Under these assumptions, scenarios that allow for increased investment in Natural Gas fired generation will still permit investment in CHP under GHG emissions reductions goals. The model does not include the constraints of providing ancillary services and ramping capabilities; these factors do not impact the type or quantity of new generation required under the modeling scenarios, however they are a necessary component of the reliable operation of power grids.

3.14.2 Generation Capacity in 2020

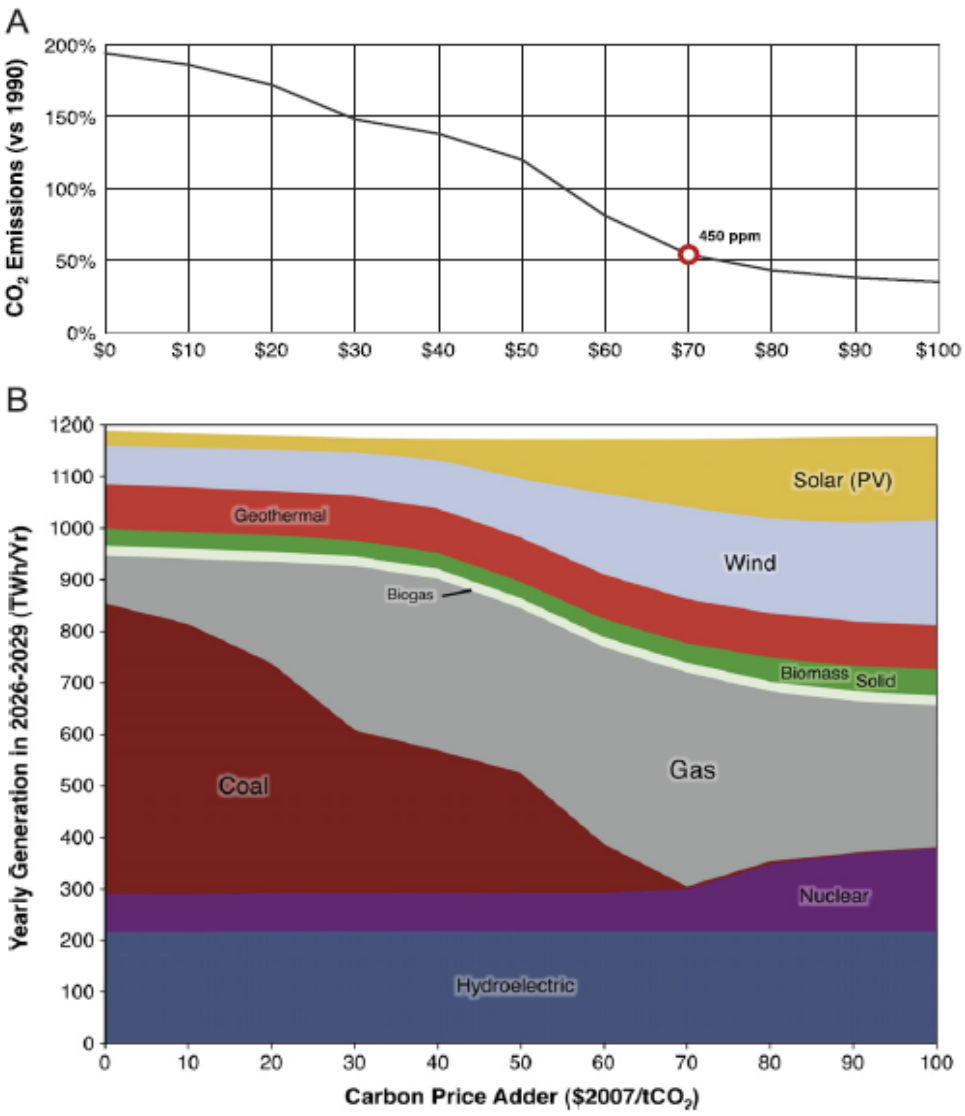
Results are shown below from a SWITCH modeling effort for the Western U.S. power grid[19]. Using RPS goals for within the WECC, and assuming a market wide carbon price adder, the

[18] Nelson, J., J. Johnston, A. Mileva, M. Fripp, I. Hoffman, A. Petros-Good, C. Blanco, and D.M. Kammen, "High-resolution modeling of the western North American power system demonstrates low-cost and low-carbon futures," Energy Policy 43: 436-447, 2012.

[19] Nelson et al., 2012.

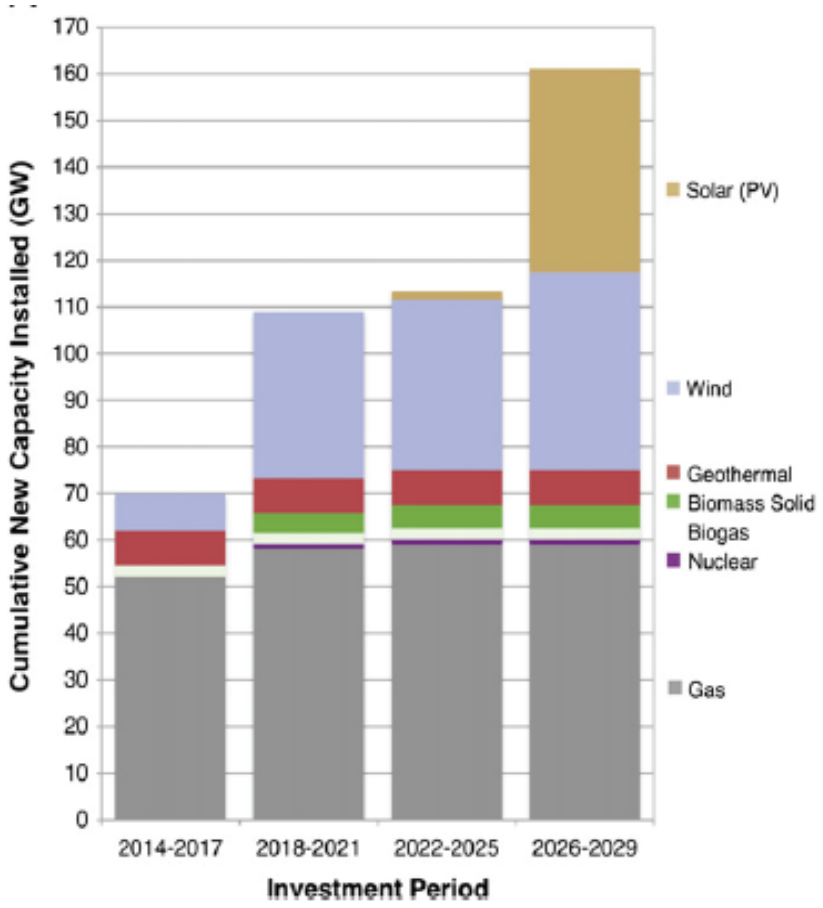
authors investigated the changes in power generation, distribution, and transmission investment as CO2 prices increased in the market. Their results are presented below in Figures 3-1 and 3-2.

Figure 3-1: Carbon Emissions Reduction and Distribution of Yearly Generation as a Function of Carbon Price Adder



Source: Nelson et al., 2012.

Figure 3-2: Cumulative new capacity at a Carbon price adder of 70 $/tCO2



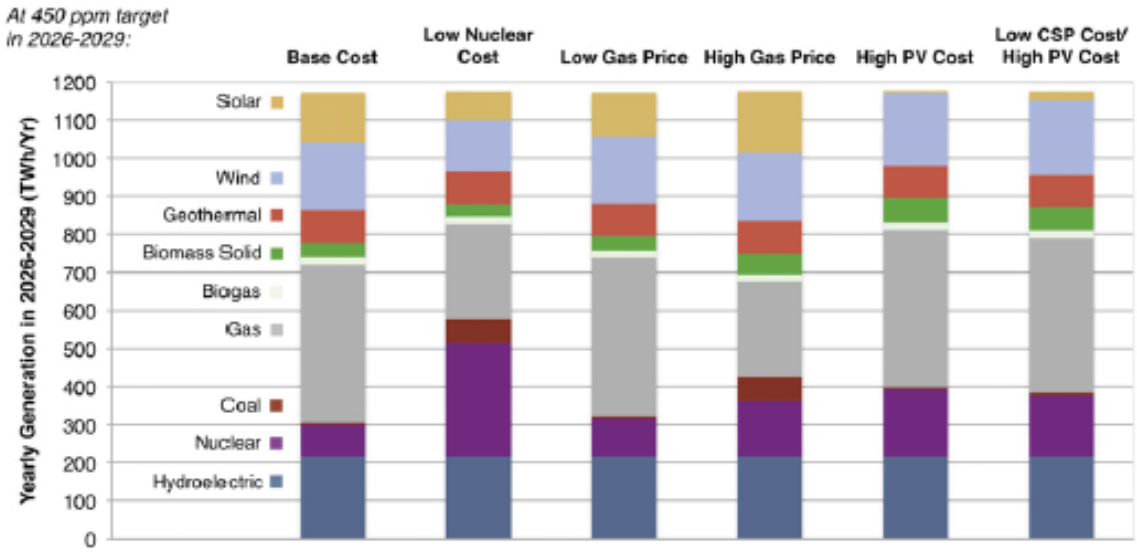
Source: Nelson et al., 2012.

As the carbon prices within the WECC are simulated to potentially increase, the authors show that over time coal-based generation decreases significantly, and is substituted first by natural gas generation, and then by solar, wind and nuclear capacity[20]. While natural gas fired generation is still subject to carbon costs, over the long run within the WECC, it remains an economical alternative to coal fired generation through 2029. Given the low carbon intensities of CCGT and CHP installations, these facilities will continue to be a necessary component of generating capacity in the WECC. In terms of new capacity additions, the SWITCH modeling results show that new investment in natural gas-fired generation will continue through 2021, where new capacity additions will consist primarily of wind and solar facilities.

[20] We note however, that recent events including the accident at the Fukushima reactor in Japan may reduce the likelihood of future investments in nuclear power.

The authors also presented results from additional price scenarios including: "Low Nuclear," "Low Gas," "High Gas," "High PV," and "Low CSP/PV" costs. These results are depicted in Figure 3-3.

Figure 3-3: WECC Capacity Additions by 2029 for Technology Price Scenarios



	Base Cost	Low Nuclear Cost	Low Gas Price	High Gas Price	High PV Cost	Low CSP Cost/ High PV Cost
Carbon price adder ($2007/t$CO_2$)	70	59	87	66	84	86
Power cost ($2007/MWh)	113	110	110	114	114	114
Cumulative new transmission built by 2030 (10^3 GW-km)	9.8	6.0	9.0	11.7	12.0	12.3

Source: Nelson et al., 2012.

Cumulative capacity additions for Natural Gas fired generation under these scenarios remains consistent with the exception of "Low Nuclear" and "High Gas." Under these scenarios, natural gas generation is less competitive with other base-load generation technologies, and increased capacity additions are distributed between nuclear, biomass, and coal fired generation.

3.14.3 Challenges for CHP Adoption in California

While the WECC level modeling results show that there is sustained need for natural gas fired generation capacity through 2029, there are regulatory and operational challenges that may limit the adoption of CHP within the confines of the California market. The regulatory hurdles include GHG emissions reporting and allowance purchases, the lower average greenhouse gas emissions for electricity produced within California versus electricity imports, and the limited ability of operators of CHP to participate in energy markets.

Operationally, CHP is limited by the need to be thermal load following in order to operate at peak efficiency, limited ramping capabilities, and operational limitations that are imposed by regulatory entities. While some power export from CHP facilities is now being allowed by

California IOUs under recently-modified market rules, CHP systems still face restrictions and obstacles with regard to fully participating in utility energy, capacity, and ancillary services markets. However, recent revisions to CAISO procurement procedures granting scheduling priority for CHP systems are a key positive development.[21]

3.15 State-Level CHP Adoption

In 2013, the Lawrence Berkeley National Laboratory (LBNL) published a report titled "Encouraging Combined Heat and Power in California Buildings" under the Public Interest Energy Research Program (PIER) for the California Energy Commission. This study uses a "bottom-up" approach to simulate Distributed Energy Resource adoption for a select subset of commercial building load profiles within California, and extrapolate market wide adoption based on the optimization results for the test load profiles. This report provides aggregate results for technology adoption across the California commercial building stock, and provides insight to the estimated impact of various policy options including grid de-carbonization, feed-in tariffs and incentive programs. The results of the LBNL study are presented in the context of Governor Brown's goals for 6.5 GW of additional CHP capacity by 2030, and investigate the state policies that may impact adoption of CHP.

3.15.1 DER-CAM Summary

The "bottom-up" model utilizes the optimization tool "Distributed Energy Resources Customer Adoption Model" (DER-CAM), developed at the LBNL. Given hourly load shapes, tariffs, CHP performance and cost data, avoided emissions from the bulk electricity grid, and solar radiation, the object of DER-CAM is to minimize total annual costs or CO2 emissions from a site. The model has been used to analyze CHP economic and market potential in various locations, including specifically in California.[22][23][24]

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[21] California Independent System Operator, "Regulatory Must Take Generation: Revised Straw Proposal," January 10, 2012.

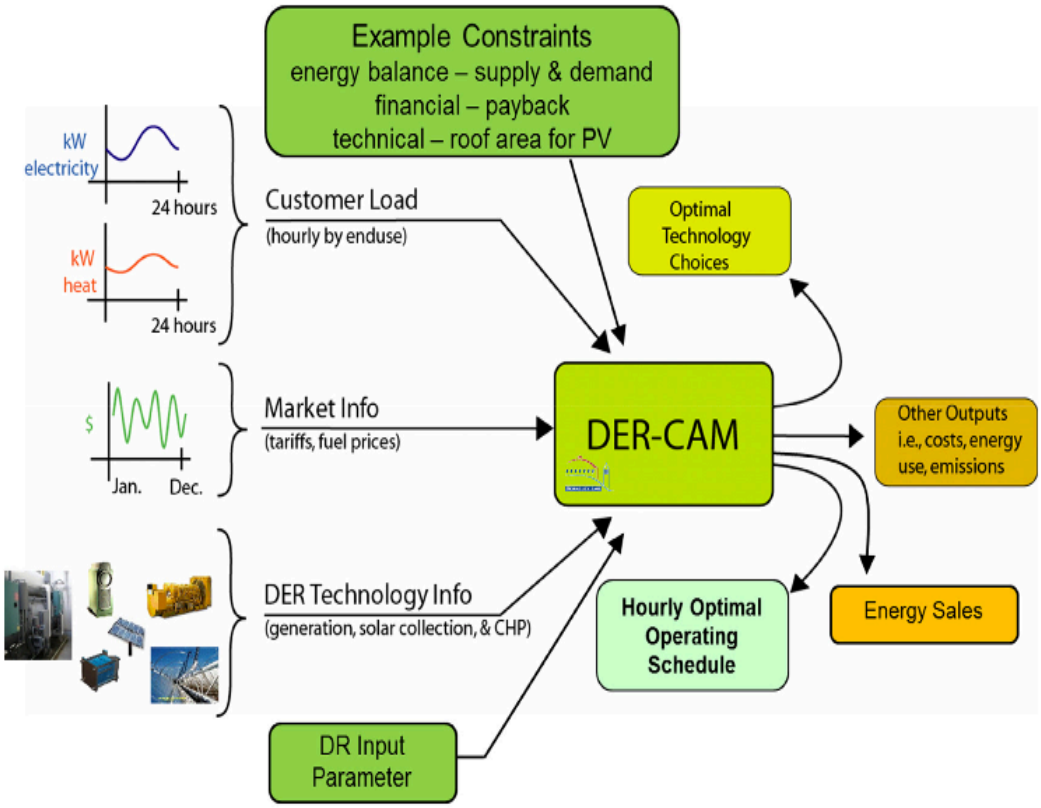
[22] Cardoso, G., M. Stadler, M.C. Bozchalui, R. Sharma, C. Marnay, A. Siddiqui, and M.Groissböck, "Microgrid modeling using the stochastic Distributed Energy Resources Customer Adoption Model (DER-CAM)," Berkeley Lab Environmental Energy Technologies Division, INFORMS Annual Meeting, Phoenix, AZ, 15 October 2012, LBNL-5937E, 2012.

[23] Stadler, M., C. Marnay, G. Cardoso, T. Lipman, O. Mégel, S. Ganguly, A. Siddiqui, and J. Lai, "The CO2 Reduction Potential of Combined Heat and Power in California's Commercial Buildings," Clean Tech Law & Business Journal, LBNL-2850E, 2010.

[24] Stadler, M., M. Groissböck, G. Cardoso, A. Müller, and J. Lai, "Encouraging Combined Heat and Power in California Buildings," Berkeley Lab Environmental Energy Technologies Division, LBNL-6267E, 2013.

For the LBNL studies, CHP has been considered in parallel with other technologies, such as solar PV, solar thermal, and advanced electricity storage. The optimization is technology neutral and assumes that the decision maker will choose a portfolio of options that result in least total cost or CO2 emissions. Passive measures (i.e. additional insulation, different glazing) are not considered. As shown in Figure 3-4, the model outputs the operating schedule for the optimal selection of technologies, as well as total costs, CO2 emissions, and the new building load shapes.

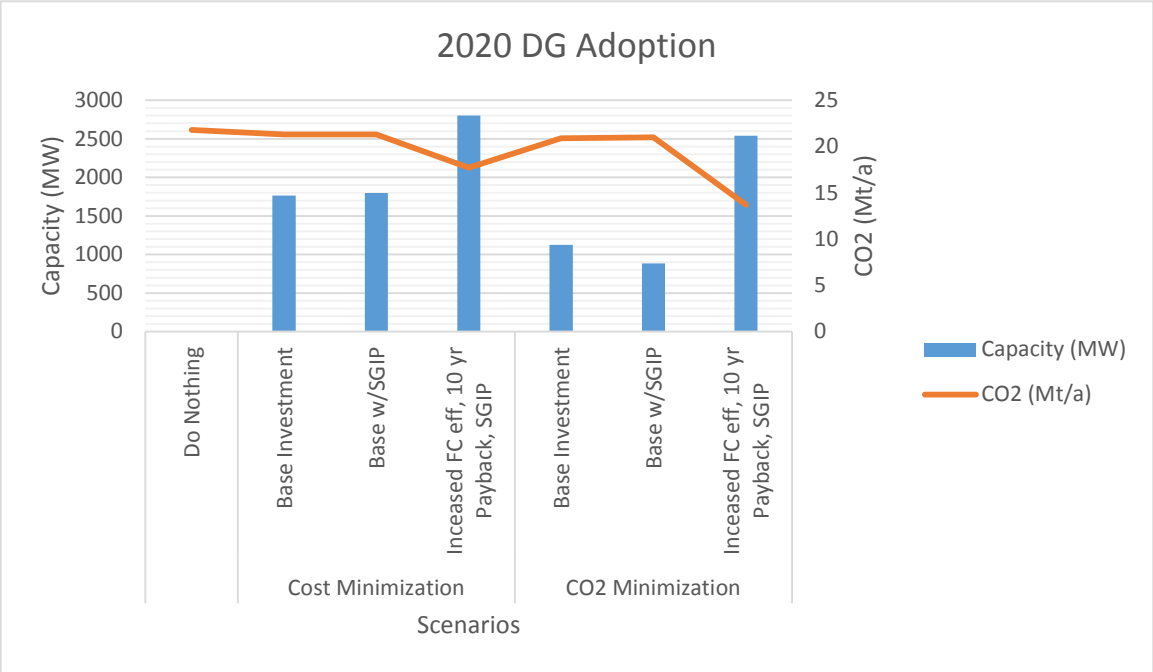
Figure 3-4: DER-CAM Schematic



3.15.2 Summary of Results for 2020

For detailed results of the LBNL study, readers may refer to the full report referenced above[25]. Here a summary of the study findings with regard to the impacts of the Self Generation Incentive Program, GHG emissions reduction targets, and other policy impacts to market adoption are discussed. A summary of CHP adoption results is presented below in Figure 3-5.

Figure 3-5: Estimated Cumulative DG Adoption Through 2020



Source: Stadler et al., 2013.
Note: "Mt/a" refers to megatons of CO2 per annum (year).

Using an investment payback period of five years, the study found that a pure "cost-minimization" strategy resulted in 1,754 MW of installed CHP capacity without considering impacts of SGIP. With SGIP incentives in place, the total installed capacity of CHP increased only modestly to 1,796 MW. Increasing the allowable system payback period from 5 to 10 years and allowing for higher fuel cell electrical efficiencies increased total adoption of CHP to 2,801 MW, but also dramatically increased solar PV adoption as well.

Under CO2 minimization strategies, a significant decrease in CHP adoption was observed, owing to the lower carbon emissions of some other types of generation (e.g., wind and solar PV). Without the SGIP in place, 1,124 MW of CHP were adopted under the model assumptions. With the SGIP program in place, installed capacity of CHP is lower at 885 MW. Further relaxing constraints on payback periods and increasing the technology performance of fuel cells results in 2,540 MW of CHP installed, still lower than adoption under cost-minimization scenarios. The decrease in adoption under CO2 minimization scenarios with SGIP can be explained because of

[25] Stadler et al., 2013.

greater adoption of renewable technologies, such as solar PV, in place of CHP. Another factor may be that the operational constraints of SGIP funds results in few facilities qualifying for funds, and therefore not adopting DG. This hypothesis is investigated further at the facility level.

For either objective (cost reduction and CO2 minimization), while the model does not show the SGIP to significantly increase the total capacity of installed CHP, under certain assumptions it does increase adoption of fuel cells. For example, assuming an increased allowable payback period of 10 years, and future increases in fuel cell electrical efficiency to 46 percent, up to 2.1 GW of fuel cell capacity through 2020 is feasible under CO2 minimization strategies.

3.15.3 Discussion of Results

The "bottom-up" DER-CAM modeling provides a broad summary of technology adoption under various market scenarios, however in aggregate; there are several results whose causes are not readily apparent from the aggregate results. While simultaneous consideration of all technologies provides a best-case scenario for adoption of DG technologies, it is difficult to determine which factors specifically affect CHP adoption, given the simultaneous effects (e.g. peak load reduction with PV vs. CHP facility operation). Furthermore, the results of the study indicate that the guidelines to qualify for SGIP funds may place operational and investment restrictions that, while encouraging the decrease in CO2 emissions, may disincentivize adoption of CHP. These issues are explored further at the level of individual facilities to determine how these factors change technology adoption patterns.

3.16 Facility-Level Example SGIP Impacts

The LBNL Microgrid modeling effort (discussed above) takes a bottom up approach to investigating the potential for CHP in California commercial buildings; however, this modeling effort takes an "All-In" approach and does not consider the impacts of policy options on individual commercial sites. To illustrate these impacts and how they might affect the investment decisions at the individual facility level, the PCEAC has modeled CHP adoption using DER-CAM for facilities with load shapes derived from the California Commercial End Use Survey (CEUS). The following factors are investigated:

- Impact of SGIP funds on facility level investment decisions in isolation of other investment options.
- Impact of the requirements of SGIP funds on technology adoption.
- Impact of the broadening of Cap-and-Trade in California in 2015 to include fuels.

The impacts of each policy option are modeled separately for the sample facilities included in this study. Further work should examine the combined effects of these policy options on technology adoption, but the combined effects are not considered in this study to isolate the impacts of each policy instrument.

3.16.1 DER-CAM Modeling

The PCEAC utilized the DER-CAM Investment and Planning optimization tool to investigate the impacts of specific factors on the adoption of CHP at typical facilities. Utilizing building load data from the commercial end use survey (CEUS) database, the team at the PCEAC generated sample building load profiles for commercial office buildings in California utility service territories.

These categories of commercial structures were chosen to provide examples of CHP installed in building types with load profiles and thermal energy demand similar to building types for which there may be a market for CHP. Building types not considered here may have different optimal technology selection with the SGIP, and further work should investigate the minutiae of how incentive structures might change technology selection within different climate zones and utility service territories. More details on the assumptions used in the facility level analysis can be found Appendix B.

The impacts of SGIP and CO2 emissions reduction measures were modeled for individual facilities, limiting investment options to CHP and switching from centrifugal to absorption chillers. Technology options not considered are advanced energy storage, thermal storage, solar-thermal, or solar-PV adoption. This isolates the impacts of the scenarios considered to CHP adoption only, at the cost of exploring potential benefits of investing in continuous technologies in addition to CHP. For each case, technology adoption was considered against the "Do-Nothing" baseline alternative to determine whether investments met minimum payback period criteria.

Building load profiles were generated for prototypical buildings in forecasting climate zones 05. Based on a review of existing installations, this forecasting zone encompasses a large proportion of existing commercial CHP capacity within the state of California, comprising large parts of the metropolitan San Francisco Bay Area.

3.16.2 Model Assumptions

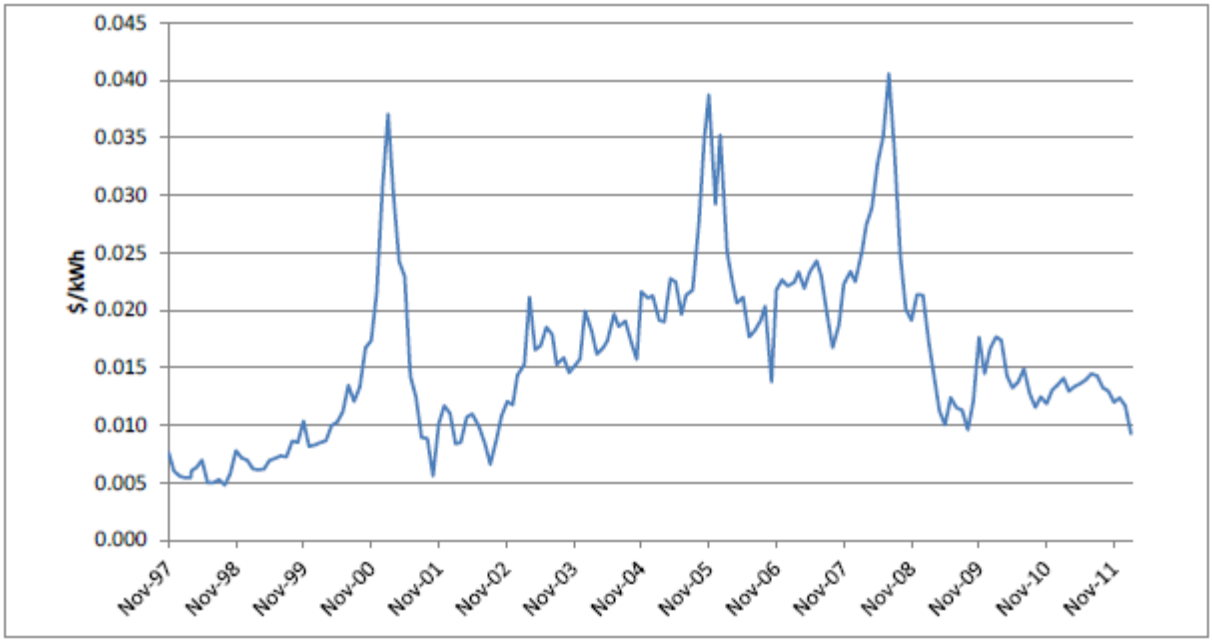
A detailed description of assumptions used to model technology adoption can be found in Appendix B. Note that the effects of the federal investment tax credit (available to for-profit entities with tax liability) are not considered in this analysis and may have a significant positive impact on project economics where that benefit can be captured.

3.16.3 Results for Onsite Cost Minimization

Optimizing the onsite cost minimization for CHP systems is principally driven by the difference between electricity tariffs and the cost of natural gas, defined as the spark-spread. When the spark spread is very high, CHP is an economical option, and adoption rates increase. As the spark-spread narrows, the economics of CHP suffer, and the adoption of CHP decreases and existing plants may be idled to take advantage of lower electricity prices.

In the eleventh year SGIP impact evaluation[26], it is noted that a large proportion of capacity installed in the early years of the SGIP, when the primary goals were promotion of emerging technologies and cost reductions, are off-line or decommissioned. While there may be various operational issues contributing to the low capacity factors for vintage SGIP installations, a primary contributing factor may well be the high volatility and periodic spikes in natural gas prices and erosion of the spark spread, shown in Figure 3-6 below.

Figure 3-6: Weighted Average Cost of Natural Gas, PG&E Service Territory



Source: Pacific Gas and Electric Company, 2012.

While tariffs are adjusted to reflect the variation in natural gas prices, in California they are partially decoupled from the cost of natural gas. Natural gas comprises approximately 45 percent of power produced within California, with the remainder coming predominantly from hydroelectric and nuclear power plants[27]. Recently, given historically low wholesale natural gas prices, the economics for gas fired distributed generation are improving. Coupled with feed-in tariffs authorized under AB1613, and the extension of SGIP funding, CHP has the potential for expanded adoption within California.

The SGIP, however, is expected to only result in minimal improvements for project economics, given the modeling results described here that examine potential system adoption for example

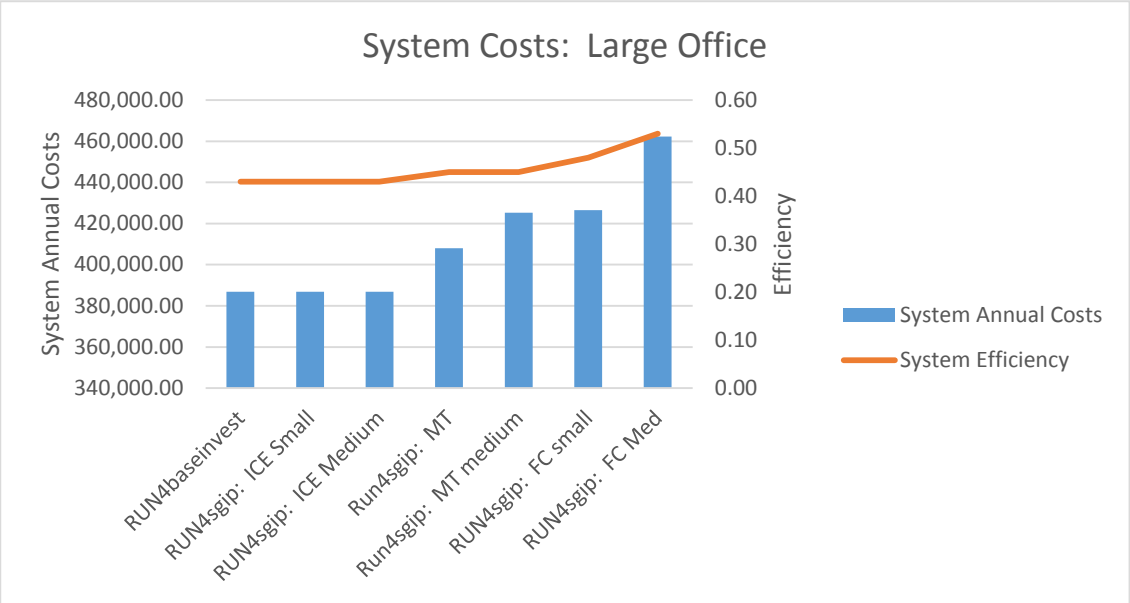
[26] Itron Inc. *CPUC Self-Generation Incentive Program Eleventh-Year Impact Evaluation*, Davis California Pacific Gas & Electric 2012.

[27] ICF International, Inc. *Combined Heat and Power: 2011-2030 Market Assessment.* CEC-200-2012-002, Sacramento: California Energy Commission, 2012. (http://www.energy.ca.gov/2008publications/CEC - 200 - 2008 - 002/CEC - 200 - 2008 - 002.PDF)

building load profiles The goals of the program have shifted from the promotion of advanced energy technologies to the implementation of net-GHG reducing installations. Based on the low-capacity factors and early retirement of systems under earlier incarnations of SGIP program rules (2001-2010) identified by the eleventh year program impact report[28], the most recent program rules include a hybrid performance based incentive. As described above, this incentive structure pays 50 percent of incentive up front, with the remainder paid out over time, to encourage efficient and continued operation of distributed generation. With current rules the remaining 50 percent of funds is paid out over five years if GHG emissions thresholds and average capacity factors are satisfied.

To demonstrate the impact of the SGIP on project economics, the optimal selection of CHP technologies for example host sites is compared to baseline energy purchases both with and without SGIP eligible technologies. For a large (>30,000 ft2) commercial office building, with annual energy consumption normalized to 2 GWh, Figure 3-7 shows the total annualized energy costs for a variety of scenarios and incentivized technologies.

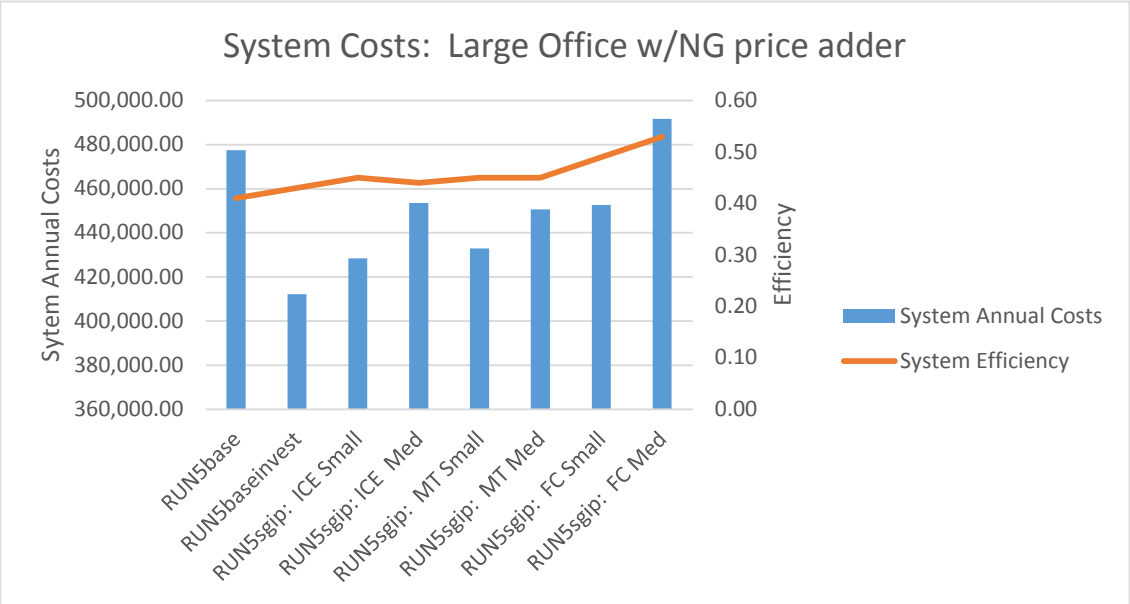
Figure 3-7: Annual Costs and Efficiency Estimates for Large Commercial Building (no natural gas price adder)



Note: FC = fuel cell; ICE = internal combustion engine; MT = microturbine.

[28] Itron, 2012.

Figure 3-8: Annual Costs and Efficiency Estimates for Large Commercial Building (with natural gas price adder)



Note: FC = fuel cell; ICE = internal combustion engine; MT = microturbine.

For this example large commercial office building, the availability of the SGIP does not result in lower annualized costs for investment in distributed generation compared to the optimal technology selection with non-eligible systems. While forcing the adoption of SGIP eligible technologies does result in higher total system efficiencies, it does not result in lower annualized energy costs. The stated goals for the SGIP are onsite GHG emissions reductions¸ so in this regard, the incentive decreases the cost of technologies with lower total GHG emissions, but from an economics standpoint, systems that satisfy the minimum requirements of the SGIP are not the most economical investment decision.

We hypothesize this is due to the capacity factor and minimum system efficiency requirements of the SGIP program. Based on the low-capacity factors and early retirement of systems under earlier incarnations of SGIP program rules (2001-2010) identified by the eleventh year program impact report[29], the most recent program rules include a hybrid performance based incentive. This incentive structure pays 50 percent of incentives up front; to encourage efficient and continued operation of distributed generation, the remaining 50 percent of funds is paid out over 5 years if GHG emissions thresholds and average capacity factors are satisfied.

The DER-CAM constraints allow for investment in SGIP eligible systems that do not meet the 80 percent capacity factor requirement, though they do not receive 100 percent of incentive funds. Recent DER-CAM results, however, indicate that systems operating under both cost and GHG minimization strategies may have optimal operation schedules that result in lower than 80

[29] Itron, 2012.

percent capacity factors. The SGIP focuses on systems that operate with high capacity factors, but there is a possibility that the most economically-efficient operation schedule for a facility may not receive 100 percent of incentive funds under current program rules.

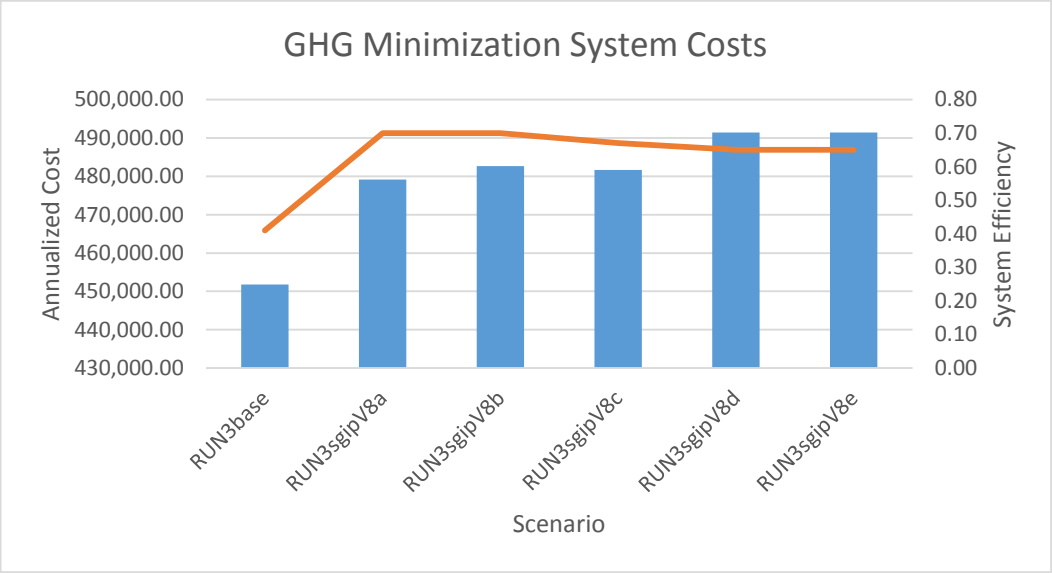
Commercial office buildings also have relatively low thermal energy demands, primarily for space heating, reheat, and domestic hot water. In the winter season, when thermal loads are higher, the highest thermal energy demand occurs early in the day to pre-heat the building before leveling off for the rest of the day, and electricity loads follow a diurnal cycle with peak loads in the afternoon. This creates a challenge to have a large capacity CHP installation that also meets minimum capacity factor requirements. With a larger thermal load, the ability to export power may improve the economics of CHP installations; however the low thermal load of commercial buildings necessitates that efficient CHP installation will rarely produce enough energy to exceed on-site electricity loads.

For commercial office building load profiles, on average the SGIP does not appreciably result in improved project economics for cost-minimization strategies. For sites that require or specify higher efficiency levels, SGIP funds help decrease total annualized costs, and will improve project economics. Further investigation needs to be undertaken to determine at what point increased natural gas prices and electricity rates as a potential result of California cap-and-trade regulations will influence investment decisions for CHP with, and without, SGIP funding availability.

3.16.4 Results for Onsite CO2 Minimization

Under CO2 minimization strategies, large office buildings can achieve economical reductions in annual energy expenditures without the assistance of SGIP rebates. The optimal technology chosen, however, is limited to internal combustion engines (ICEs), a mature technology with moderate high potential waste heat utilization and low capital costs per kW of installed cost. With higher thermal loads for space and water heating, microturbines may be a more economical choice. For the impact of SGIP funds under the scenario onsite CO2-minimization, each technology option was simulated simultaneously with non-eligible to estimate the impact of choosing each eligible system, shown in Figure 3-9 below.

Figure 3-9: Annual System Cost and Performance for GHG minimization



Note: RUN3sgipV8a = SGIP with ICE; RUN3sgipV8b = SGIP with small microturbine; RUN3sgipV8c = SGIP with medium microturbine; RUN3sgipV8d = SGIP with small fuel cell; RUN3sgipV8e = SGIP with medium fuel cell.

For each technology option for a large office building normalized to 2 GWh of electricity consumption, only one SGIP eligible generator was installed, with the remaining CHP capacity comprised of an ICE with CHP, but without SGIP eligibility. It is hypothesized that the capacity factor requirements to qualify for SGIP funds require that any qualifying systems run in essentially a "base-load" mode, and cannot ramp to meet the energy demand without violating SGIP requirements for minimum capacity factors. By installing generators in lead-lag configurations, DER-CAM allows for one system to operate at base-load configuration and satisfy SGIP requirements, while the other ICE generators in this case ramp to meet demand. The relative modularity of CHP systems provides this type of operational flexibility, but with complex interactions with the potential benefits of the SGIP on individual system and site-level economics.

3.16.5 Conclusions

An analysis of optimal investment decisions at the individual building level shows that CHP can at least modestly reduce site level energy costs while increasing total system efficiency in some settings. Results indicate that SGIP eligible systems, while having lower annualized costs than the "Do-Nothing" alternative, are less optimal than a non-eligible system for commercial office buildings. Despite this, the SGIP can improve the economics of investing in CHP for facilities that will install CHP with high total-system efficiencies, or with GHG emission reduction as a primary constraint. Further work should investigate these trends and results across all climate zones, as well as selectively remove constraints from the SGIP to determine which has the greatest impact on the SGIP goals of promoting economic systems that result in a net reduction of GHG emissions.

CHAPTER 4:
Building Energy Analysis and Utilization Statistics

4.1 Introduction

In order to understand the application of CHP in the California market, it is crucial to better understand the energy demand profiles and performance of target facilities. These characterizations can inform the CHP potential and equipment sizing and types that can be most appropriate for given types of buildings and locations.

For CHP to be cost effective, the waste heat must typically be recovered most if not all of the time. For most applications that consider CHP, monthly and yearly quantities of electricity and heat use indicate that a CHP system should work efficiently to be cost-effective. However, this is often not the case due to the miss-match between the moment-by-moment electric and heat demand. As a result, CHP systems need, in principle, to match the timing of the needed heat and electricity on a real-time basis, since storing either heat or electricity even on a short-term basis is not economically practical.

In addition, the temperature of waste heat from the DG generator must meet minimum quality levels demanded by the load requirements. If either of the timing or quality does not match, then only a small fraction of the waste heat can be used, greatly decreasing the overall efficiency of the CHP unit and increasing overall emissions from the unit. As a result, time resolved information regarding building load (electrical and thermal) demands and how DG/CHP systems are deployed to optimally meet this demand is needed in order to accurately determine the emissions profile of the system.

To better understand the opportunities and the subsequent impact of wide spread application of DG with waste heat recovery it is vital to: 1) identify facilities that would most likely benefit from the application of CHP; 2) understand and document the typical energy profiles; and 3) assess the effects, if any, of localized emissions from the DG/CHP on the immediate surroundings. In the CEC Program, "Realistic Application and Air Quality Implication of DG and CHP in California", an assessment of a variety of building types were evaluated for energy intensity, waste heat utilization potential, and impact on energy consumption in the built environment[30]. Specifically the project aimed to:

1. identify facilities that would most likely benefit from the application;
2. understand and document the typical energy profiles; and
3. assess the effects, if any, of localized emissions from the DG/CHP on the immediate surroundings.

[30] Hack, R.L. McDonell, V.G., Samuelsen, G.S. (2011) Realistic Application and Air Quality Implication of DG and CHP in California, CEC 500-02-004, March.

The project reported here extends these results with additional analysis of the building load profile and energy data with specific focus on CHP applications in these sectors. The key factors in the evaluation were energy market potential (i.e. watts of generation potential in the sector as well as the applicable size (<20 MW)), waste heat recovery, and perceived acceptance of the technology. The facilities identified for the study and most likely to benefit from deployment DG/CHP as well as impact the grid and environment from the deployment are:

- Hospital/Health Care: 6 sites
- Hotels: 4 sites
- Jails/Prisons: 9 sites
- Colleges/Universities: 9 sites/facilities
- Large Commercial Office: 18 sites
- Food/Grocery: 12 sites (eleven grocery stores + one warehouse distribution center)

Data from these facilities, both measured, obtained from on-site energy monitoring systems (EMS) was gathered at nominally 15 minute intervals over a minimum 12-month period for each facility; in some cases the monitoring extended to 18 months or more. The measured parameters and the equipment utilized to obtain this information are presented in Appendix B.

The amount of data gathered for the 58 facilities at 15 minutes for 12 or more months resulted in an SQL database of more than 3.3 million rows. The process for the development of the database is included in Appendix C.

4.2 Data Smoothing

Over the extensive period of monitoring and collection of data for the wide range of sites, the measured data inevitably acquired errors, omissions, or simply data that could not make sense such as negative values or values many times greater as compared to immediately adjacent time step data. These values on an individual basis, compared to the balance of the year would not necessary skew averages in the data, but statistics of max, min, and standard deviation could be altered and provide an inaccurate and misleading information. To help provide a more reasonable representation, every measured parameter data for each site within each sector was reviewed for both negative values, and for values that deviated more than 4-sigma[31] from the average value for the measured parameter. While it is easy to explain the elimination of negative values as being physically unrealistic, the choice of 4-sigma as a cut-off point is perhaps subject to question. While difficult to assess in tabular form, a graphical plot of the data shows errant and random "spikes" in some of the data. They further, the data point typically do not have a reasonable, physical relation to the values immediately prior to nor after the errant point. A threshold of 4-sigma was chosen as a simple means of eliminating the obviously errant

[31] 4-sigma = 4 standard deviations = 99.994% of the entire data set is contained within 4 standard deviations

data points with minimal compromise to the what is believed to be valid data. No doubt there are other screening mechanisms that could be employed to check for errant data.

The original database from the energy-monitoring program had 3,322,667 rows. After the data were cleansed (eliminating the negative and >4-sigma deviations from average) the number of remaining rows was 3,310,913 (11,754 rows deleted = 0.3 percent of the data). Table 4-1 shows the specifics on the eliminated data deleted by parameter and reason.

Table 4-1: Data Base "Smoothing" Statistics for Elimination of Errant Data

	Deleted Rows		
Column	**Values over Avg + 4xSigma**	**Negative Values**	**Totals**
TotElecEng	2,576	3,765	**6,341**
TotoChilElecEng	1,511	27	**1,538**
TotHVACChill	1,257	0	**1,257**
TotHVACHeat	1,078	3	**1,081**
TotNG	28	0	**28**
TotProChill_SC	111	0	**111**
TotProChill_MT	204	0	**204**
TotProHeat	0	0	**0**
TotOSFBGenElec	0	0	**0**
TotOSFBGenFuel	0	95	**95**
TotOSFBWHRHeat	364	0	**364**
TotOSFBWHRChill	76	659	**735**
TotOSNFBGenElec	0	0	**0**
TotOSNFBGenTherm	0	0	**0**
Totals	**7,205**	**4,549**	**11,754**

4.3 Data Limitations

Perhaps the largest limitation of the field data obtained in this project is that the vast majority of sites were located in Southern California in a combination of SCE and various municipal utility territories whereas many other CHP sites are located in PG&E (Northern California) territory and other central/northern inland sites. Hence the data reported are geographically and meteorologically limited. Nevertheless, the data is representative of much of the State of California wherein weather extremes (very hot or very cold) are limited to areas of low population and minimal commercial/industrial development.

The data obtained from the Energy Monitoring Program is based upon a compilation of measured data and utility data. For the electric power measurements entering a facility, these were nearly all based upon utility provided 15-minute data. This was deemed perfectly reasonable based upon the utility billing grade information feed to the local utility for subsequent billing. The danger associated with trying to install current transformers and

voltage taps on entering power feeds while live was insurmountable and taking an entire facility down to install these components was inconceivable. However, on subsystems (e.g. chillers, HVAC, etc.) where power could be temporarily interrupted, specific power measurements were made and logged for the database.

The availability of equipment did limit some of the specific measurements. The power measurements were typically made with a portable power meter[32], measuring both current and voltage on up to three phases. However there were a finite number of power meters available for deployment. Hence direct power measurements were not possible in all location. This was particularly acute when monitoring the chilling loads at the food/grocery facilities wherein there were three or more power circuits to be evaluated (multiple medium temperature and sub-cooling circuits). Where possible due to availability and convenience, a single power meter could be used to measure one phase of power for each of three separate systems and making the assumption of equality on each leg (since these were motors with balanced loads on each phase), power could be calculated.

In other instances, magnetic field loggers ("mag-loggers") were installed on the contactors that would activate the chiller motors. When energized and the chiller operating, the mag-logger would sense the field as being "on." The logger would record the time of day/date for every transition of state (off – on, on – off). In principle this would work very well for relatively steady operations. However, in the food/grocery chiller operations, many of the chillers would transition hundreds of times a day and quickly fill the data logger memory limits of 8,000 transition events before the data could be downloaded. In these instances, the historical operation (e.g. 95 percent on time) was assumed for those time periods where there was no specific data for the chiller. Given the nature of the business and the need to maintain the chilling for the food "24/7," this was not considered an unreasonable assumption/ extrapolation.

Time resolved natural gas measurements were unavailable for most of the facilities. Unlike electric power, natural gas is not a time of delivery sensitive product. The program considered installing flow-metering equipment that would permit time resolved consumption information. However, unlike electric power monitoring equipment that could be installed without "lifting wires" through the application of split core current transformers, incorporating a time resolved natural gas measurement would require interruption of gas service and physical alteration of the gas supply plumbing to permit installation. No non-intrusive gas measurement devices were identified as suitable for the project. As such, virtually all sites had only monthly billing data as record of gas consumption. These records were deemed nearly useless for the desired time resolved measurements for the program but would have required extensive labor on the part of the host site to retrieve/recover this information from the archives. As such, there is no specific information on natural gas consumption provided in the data set.

Rather than specifically monitoring overall facility gas consumption, where possible, the specific output from a heating device (i.e. a boiler) was monitored. This was typically accomplished with measurement of the temperature rise and the flow rate of water across a

[32] Dent Elite Pro power meter.

boiler, both parameters that could be measured with acceptable accuracy non-intrusively. It was expected that this would be the majority of the heating/natural gas consumption needs for a facility. The primary exception to this belief is the pool-heating load associated with hotel facilities; there is no data associated with the pool heating in the database.

Air conditioning load was another problematic parameter to measure. For facilities that utilized a chiller/hydronic cooling system, either the electric energy consumed by the chiller was measured or, as with the hydronic heating, the change in temperature and the flow rate measured to assess the cooling. However, in some facilities, roof top DX (direct expansion) package air conditioning units were installed that cooled the air directly. The DX units were typically installed on Commercial Office and Food/Grocery facilities. Measurement of change in the energy in the air was not practical. In many cases there were far too many DX unit to be measured. However, in some cases, the power feeds to the multiple DX units were routed through a limited number of electric power circuits that made it practical to measure aggregate energy consumption. Based upon the measured power and the nominal coefficient of performance for the DX units, a value for cooling was obtained.

4.4 Data Analysis

As a result of the wide variety of facilities in the study, reporting specific/measured data for each facility was not practical. This data is resident in the SQL database and can be directly interrogated for future evaluation. However, to report sector wide information, the data were normalized based upon the size of the facility. Hence, reported values are energy consumption per square foot of floor space.

For the sectors, a typical (e.g. average) week for each of the seasons was developed. The seasons were defined as:

- Spring (April – June)
- Summer (July – September)
- Fall (October – December)
- Winter (January – March)

For each facility in each sector, the normalized data were segregated to reflect these seasonal divisions. An average week for the season based upon the seasonally segregated data was created based upon 15-minute intervals. To assess the variability of the data amongst the facilities, the standard deviation for each of the 15-minute intervals was also calculated.

4.5 Comparison with CEUS 2006 data

The California Commercial End Users Survey (CEUS)[33] database provides a contemporary record of another study of energy consumption/intensities for buildings. Recall that the data gathered in the studies reported here is from the 2007 – 2010 timeframe, while the CEUS database is from 2006.

Table 4-2: Comparison of UCI – CEC Data With the CEUS Database

Building Type	**Electric Energy Intensity**					**Natural Gas Intensity**	**Heat to Electric Ratio**
Source/ study	**CEUS**	**UCI - CEC**				**CEUS**	**CEUS / UCI avg**
	kwh/ ft^2/yr	kwh/ft^2/yr (Standard Deviation)				kbtu/ (ft^2-yr)	
	Annual average	Spring	Summer	Fall	Winter		
Commercial Office-small (<30K ft^2)	13.10	No Data	No Data	No Data	No Data	10.54	
Commercial Office-large (>30K ft^2)	17.70	17.8 (5.3)	19.1 (6.0)	17.6 (5.6)	17.15 (4.9)	21.93	0.36
Hospital/ Health	19.61	28.4 (7.7)	34.9 (9.2)	26.6 (7.5)	29.4 (8.4)	75.53	0.74
Hotel	12.13	22.3 (2.5)	25.6 (2.6)	22.0 (2.7)	22.0 (1.8)	42.40	0.54
Food/ Grocery	40.99	42.8 (25.7)	40.9 (11.5)	36.8 (8.9)	37.3 (9.4)	27.60	0.20
Jail/Prison[34]	(no Data)						
College/ Univ.	12.26					34.24	

The results presented in Table 4-2 are mixed. The CEUS data as presented in the report is an annual average value. The UCI-CEC data is seasonal and indicates some limited variation in energy consumption. Recall that the UCI-CEC data is predominantly for Southern California facilities and as such the limited variation may be primarily dependent upon mild climate.

[33] California Commercial End-Use Survey, CEC-400-2006-005, March 2006.

[34] The Jail/Prison category could not be normalized for intensity as floor space data could not be obtained at time of writing.

The comparison of the electric energy intensity (kwh/ft2/year) for the large commercial office seems to agree relatively well with the CEUS data (17.7 versus 17.9). Not surprising, the summer data is a bit higher associated with the increased air conditioning loads. Spring and Fall are virtually identical while Winter has lowest intensity with the majority of heating needs being addressed by natural gas systems.

The comparison of the electric energy intensity (kwh/ft2/year) for the hospital/health sector reveals a large deviation from the CEUS data (19.6 average versus 29.8 ± 8.2 average for the UCI-CEC data). However, whereas the UCI-CEC data is exclusively large extensive care hospitals (VA hospitals and University hospitals ranging from 900,000 sq-ft to 3,000,000 sq-ft and up to 500 beds), the information for the CEUS data is likely much broader and encompassing. The CEUS data appears to be a compilation of 27 separate health related facilities (SIC codes 80xx and 8360, 8361) which includes large hospitals but also includes such diverse facilities as medical and dental labs, out-patient care, nursing facilities, psychiatric facilities, and even home health care. Hence the difference between the broader based CEUS and the more focused UCI-CEC data base is not unreasonable.

To further understand the variation in the energy loads, the normalized data for electric energy intensity was developed for a typical 7-day week in each of the seasons. The data are presented as the average normalized electric energy intensity for each of the 15-minute intervals for the week as well as the standard deviation of the intensity across the facilities in the sector. In addition, the ambient temperature is also proved.

Please note that it is critical to understand that the ordinate for the electric energy intensity is presented as the normalized energy consumed for the specific 15-minute interval in units of watt-hour/sq-ft. As an example of how to utilize this information, the comparison with the CEUS data was based upon the following calculation:

Annualized Energy Intensity (as defined by CEUS data base) =

Energy intensity (Wh/ft2) x 4 (15-min interval/hour) x 8760 hr/year x 1 kW-hr/1000w-hr

Figures 4-1 through 4-4 represent the weekly variation of the electric energy intensity for large commercial office (CO) buildings for Spring, Summer, Fall, and Winter respectively. The figures show the average intensity as the bold line as well as the 1-standard deviation range of values for the intensity. Also shown for reference is the average ambient temperature for each of these typical seasonal weeks. The consumption pattern is as expected with variations weekday versus weekend coinciding with the work-week. Daily variations are also as expected effectively representing the nominal 8 – 5 workday. In as much as all of the facilities are located in Southern California, the variations in electric energy intensity can be attributed to work type and on-site equipment.

A few key observations include:

- The night and weekend minimum values are very similar and not close to zero. Rather, the minimum seems to be approximately 0.3 watt-hr/sq-ft (insensitive to season) as compared to a peaks of 0.8 – 0.9 watt-hr/sq-ft. The base load is likely a result of computer, copier, and other similar office loads that are easy to not turn off.
- The morning "start" of the day is a more rapid rise in load as compared to the evening fall in power consumption, likely a result of personnel work patterns.
- The weekend load shows greater variation in standard deviation suggesting some facilities are open as a matter of course on weekends. The rise mid-day suggests personnel on site with some (albeit perhaps reduced) HVAC load and office equipment load.
- Not unexpectedly, summer loads are higher consistent with ambient temperature.

Figure 4-1: Commercial Office Spring - 15-minute energy intensity and ambient temp versus time

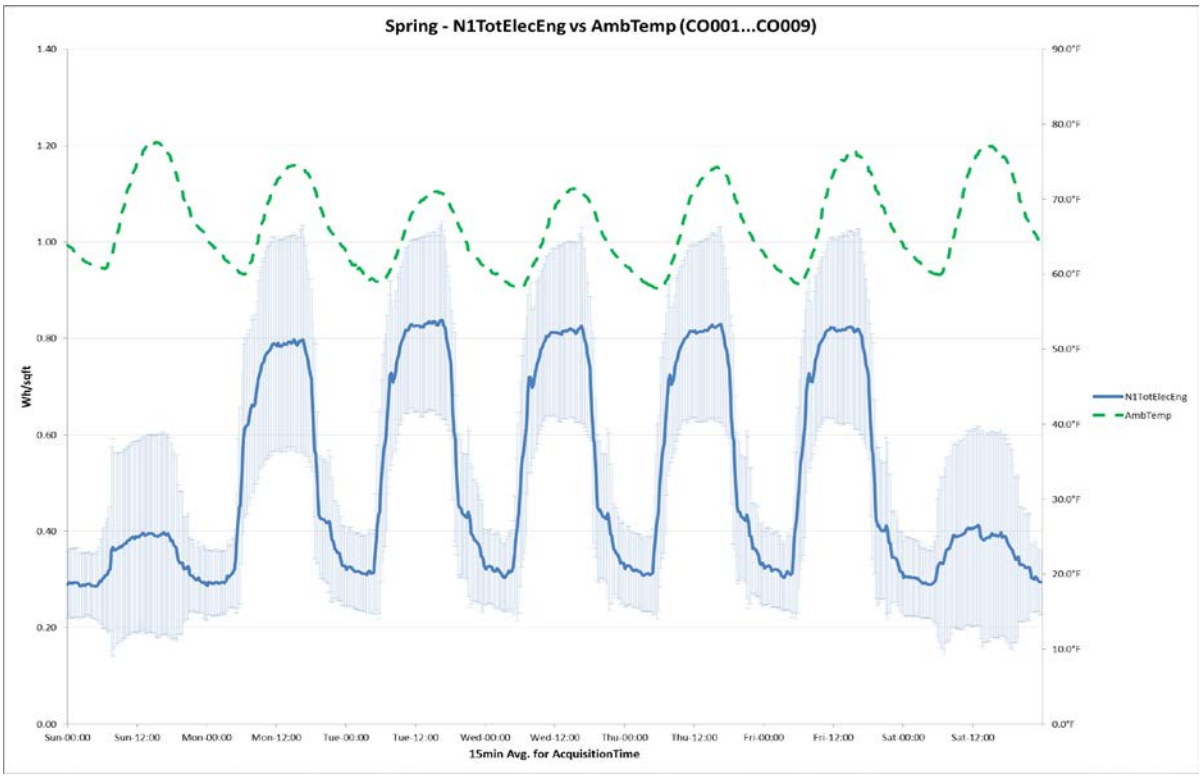


Figure 4-2: Commercial Office Summer - 15-minute energy intensity and ambient temp versus time

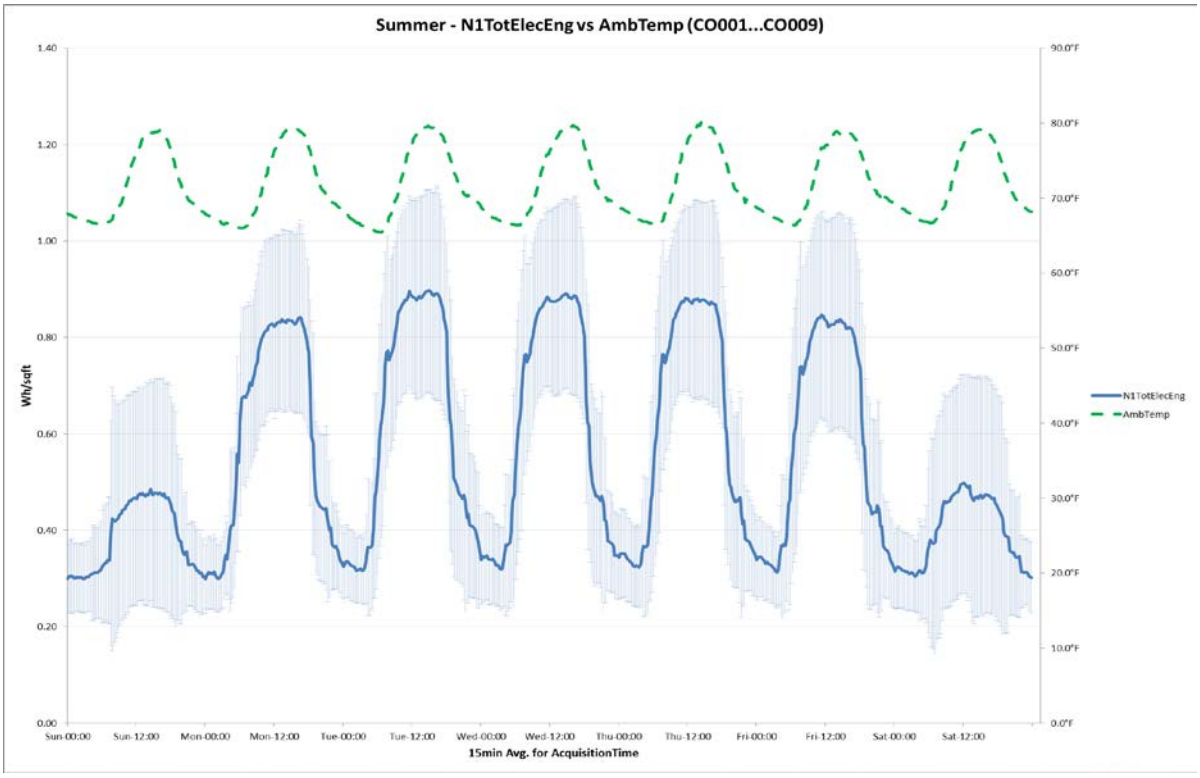


Figure 4-3: Commercial Office Fall - 15-minute energy intensity and ambient temp versus time

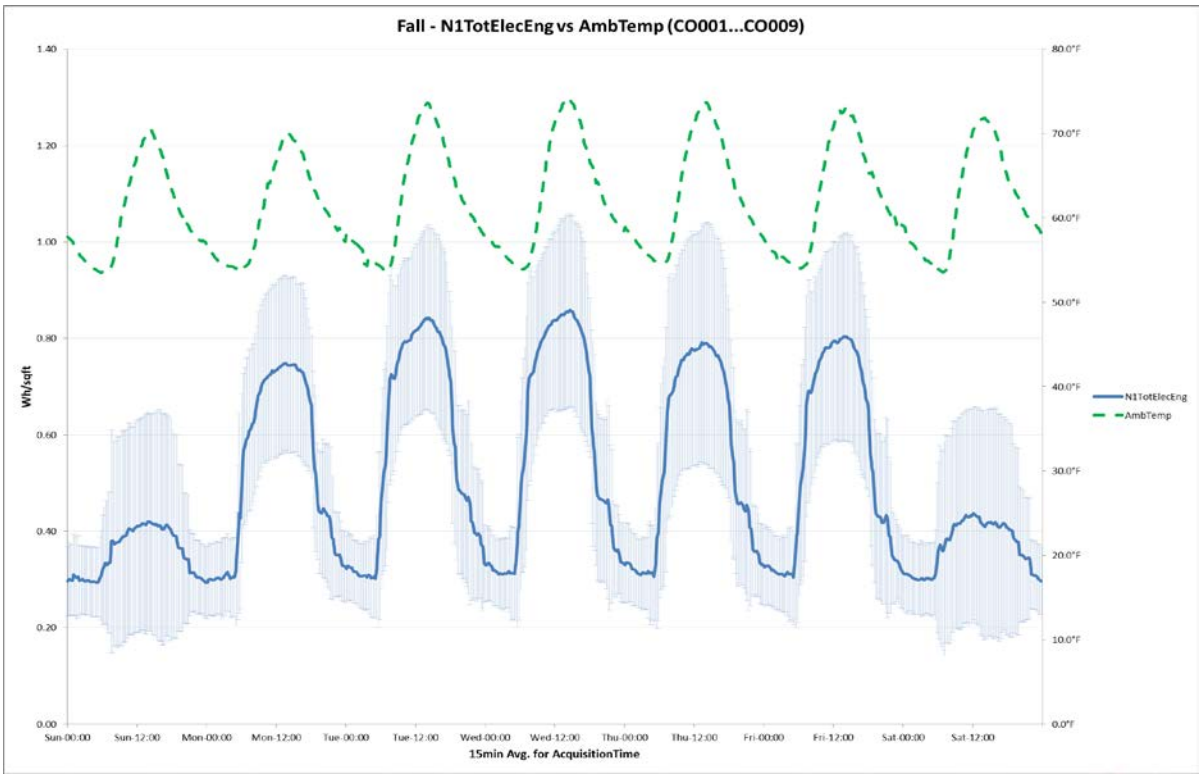
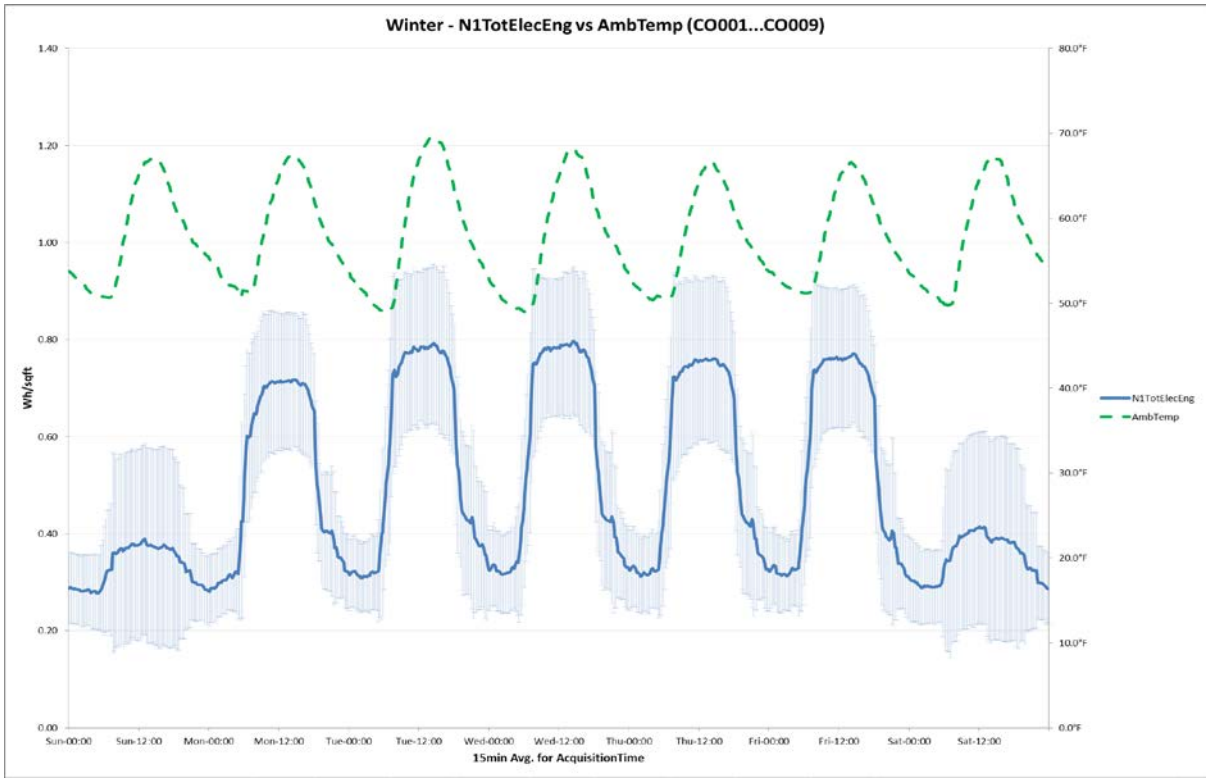


Figure 4-4: Commercial Office Winter - 15-minute energy intensity and ambient temp versus time



Figures 4-5 through 4-8 represent the weekly variation of the electric energy intensity for hospital facilities (HH) for Spring, Summer, Fall, and Winter respectively. The figures show the average intensity as the bold line as well as the 1-standard deviation range of values for the intensity. Also shown for reference is the average ambient temperature for each of these typical seasonal weeks. Given their 24/7 nature, there isn't a work-week per se. The consumption pattern is quite similar throughout the week with some reduction in energy on weekend evident as a result of reduced (but still existent) staff and overall operations to cover weekends. Daily variations are also as expected effectively representing the nominal 8 – 5 workday. In as much as all of the facilities (except one) are located in Southern California, the variations in electric energy intensity can be attributed to building age, and services. As a percentage of the average, the standard deviation is much tighter for the hospital sector than the commercial office.

Important observations include the following key points:

- The night and weekend minimum values are very similar and not close to zero. Rather, the minimum seems to be approximately 0.75 watt-hr/sq-ft (insensitive to season) as compared to a peaks of 0.8 – 0.95 watt-hr/sq-ft. This base load represents the nominal 24/7 nature of a hospital and the need to provide HVAC, lighting and services for patients and staff.
- There is not a sharp morning "start" of the day as compared to commercial office but rather a fairly well defined sine wave pattern, again likely to the "24/7" nature of the facility.
- The hospital loads show a bit more seasonal variation as compared the commercial office. This may be attributable to the larger facility size and perhaps also as a function of a sprawling facility configuration that has more surface area to volume (and as such more exposure to the environment) that a simple shaped commercial office "high rise" configuration.

These differences suggest key CHP system sizing and operational variables may be important to proper CHP system type/sizing, and each site should be considered carefully, especially between building-type sectors but even potentially within them.

Figure 4-5: Hospital/Health Spring - 15-minute energy intensity and ambient temp versus time

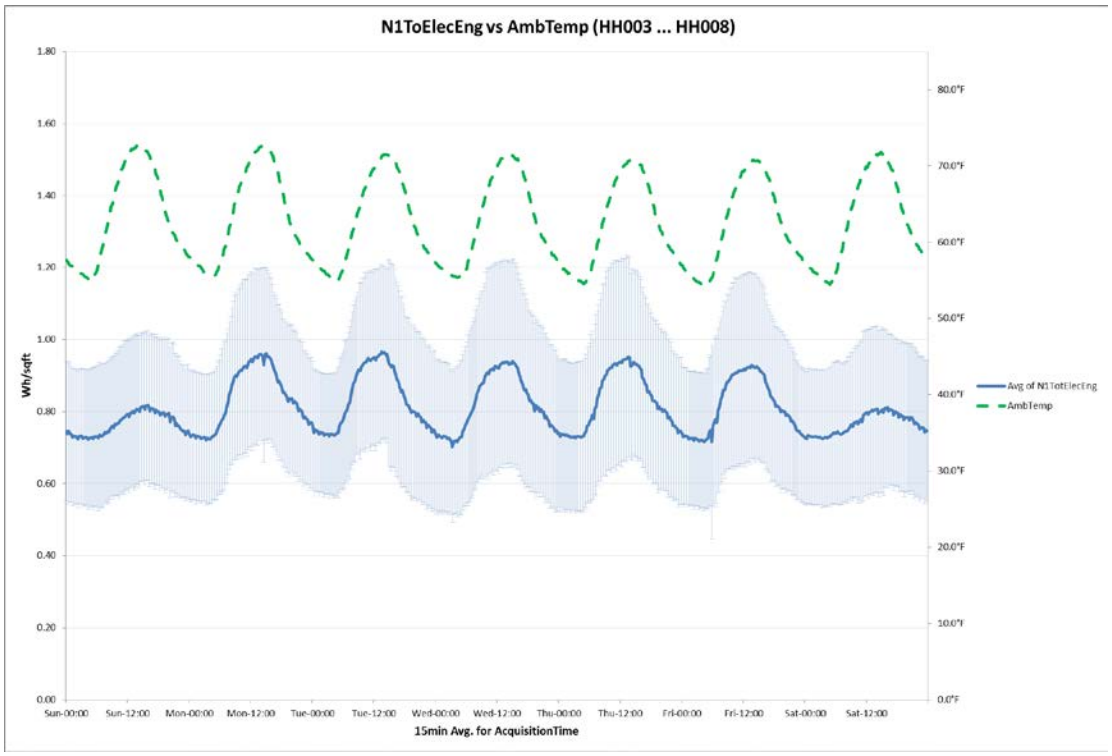


Figure 4-6: Hospital/Health Summer - 15-minute energy intensity and ambient temp versus time

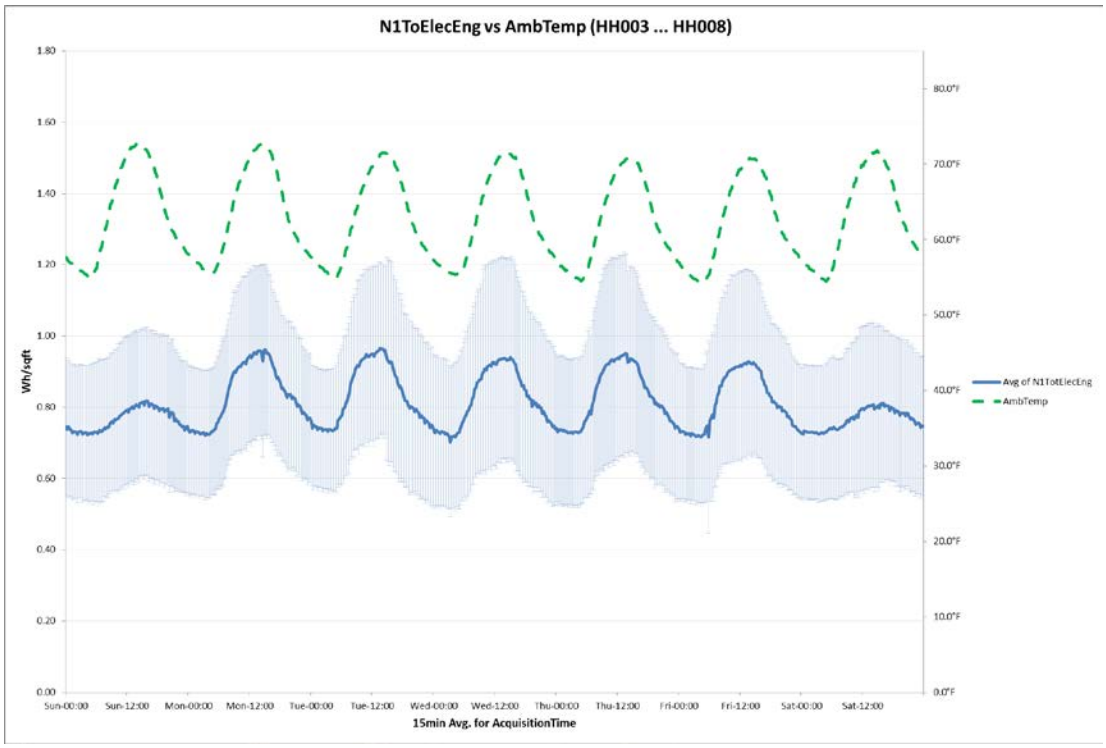


Figure 4-7: Hospital/Health Fall - 15-minute energy intensity and ambient temp versus time

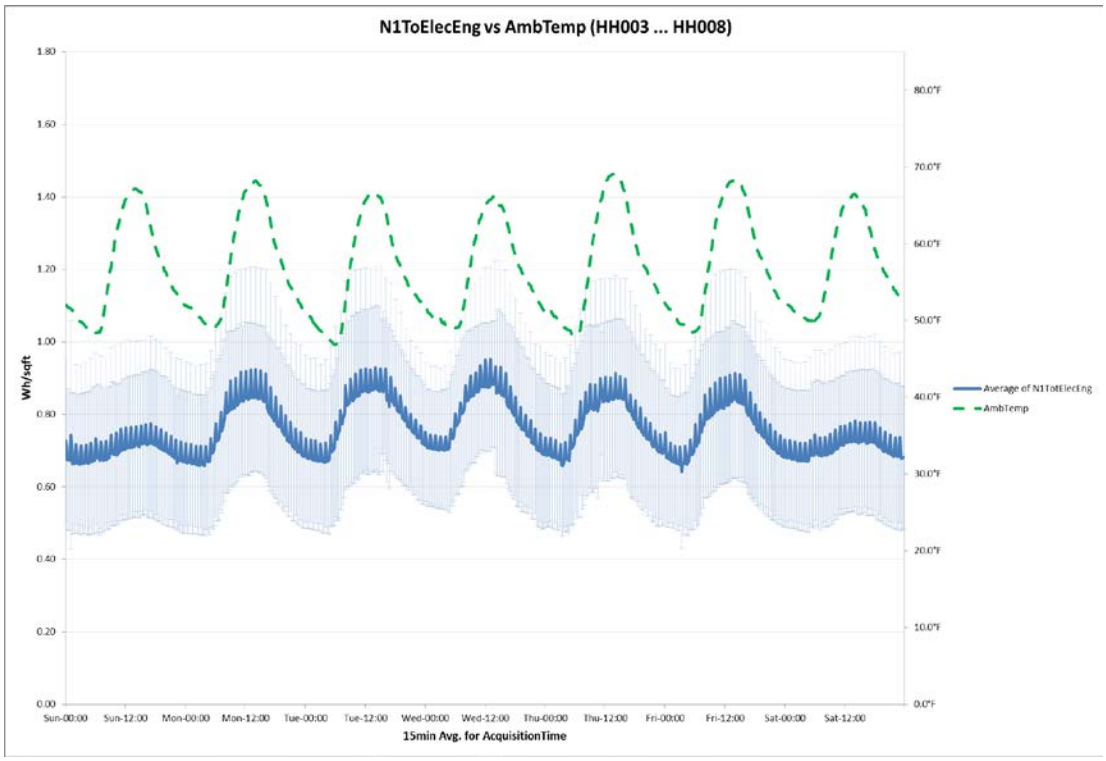
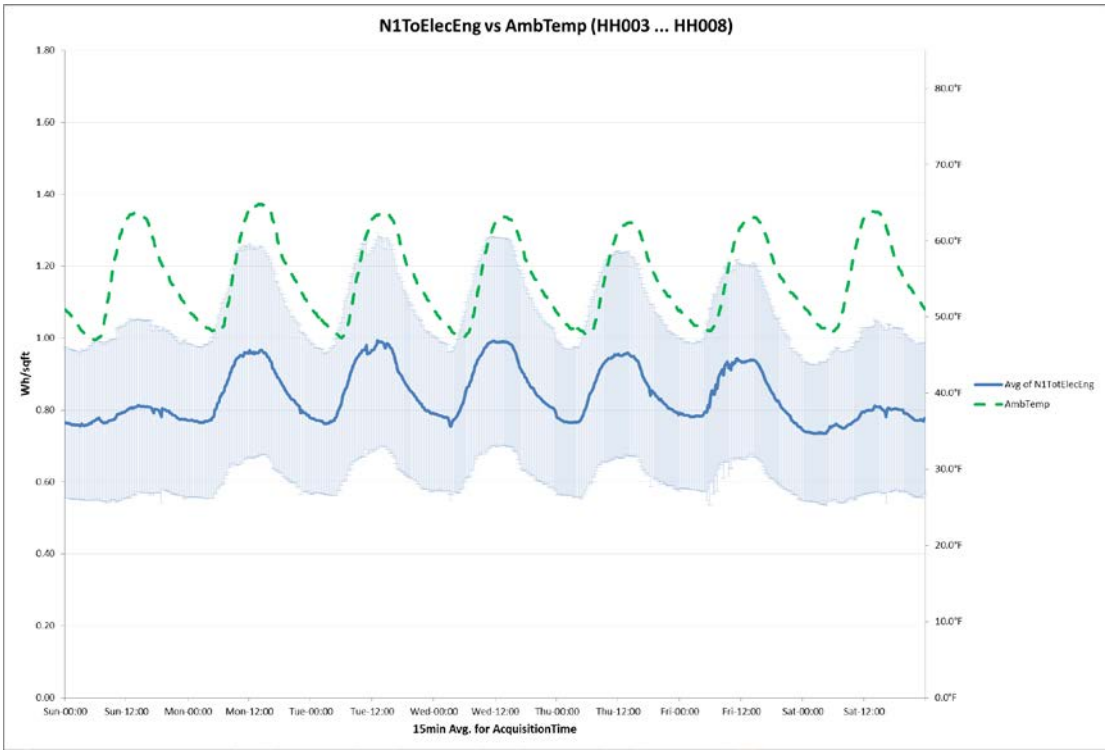


Figure 4-8: Hospital/Health Winter - 15-minute energy intensity and ambient temp versus time



Figures 4-9 through 4-12 represent the weekly variation of the electric energy intensity for hotel facilities (HO) for Spring, Summer, Fall, and Winter respectively. The figures show the average intensity as the bold line as well as the 1-standard deviation range of values for the intensity. Also shown for reference is the average ambient temperature for each of these typical seasonal weeks. Given their 24/7 nature, there isn't a work-week per se. The consumption pattern is quite similar throughout the week with virtually no discernible difference weekday versus weekend.

Important observations include the following key points:

- The minimum values are very similar and not close to zero. Rather, the minimum seems to be approximately 0.55 watt-hr/sq-ft in summer and 0.5 watt-hr/sq-ft for the other three seasons. This is consistent with perhaps a higher HVAC load to offset warmer summer nights but generally mild and little variation in the HVAC needs at night in the other seasons. Similarly, the peak intensity in the summer is 0.8 watt-hr/sq-ft as compared to 0.7 watt-hr/sq-ft for the other three seasons. As with hospitals, the care and housing of people is more of a 24/7 operation than a business office with a need to provide HVAC, lighting and services for guests and staff.
- There is similar if not as distinct morning "start" of the day as compared to commercial office and not much of the sine wave pattern as seen in hospitals. In fact the minimum is a relatively short period of time suggesting that there is a strong level of activity during the late night/early morning hours (e.g. laundry, kitchen clean-up and preparation). The morning activity is not unexpected as guests awaken.
- An interesting characteristic of the profiles is that there is no evidence of a dip in the middle of the day that could be associated with guests leaving the facility (e.g. sightseeing, business off grounds). This suggests that the majorities of the facility loads are part of the general operation of the hotel and commons spaces and not strongly tied to the guest count nor their behavior.

These results suggest that hotel building loads are distinct from other building types in key ways, and because of their relative stability may be attractive options for CHP system installation, but again with detailed study required on a site level.

Figure 4-9: Hotel Spring - 15-minute energy intensity and ambient temp versus time

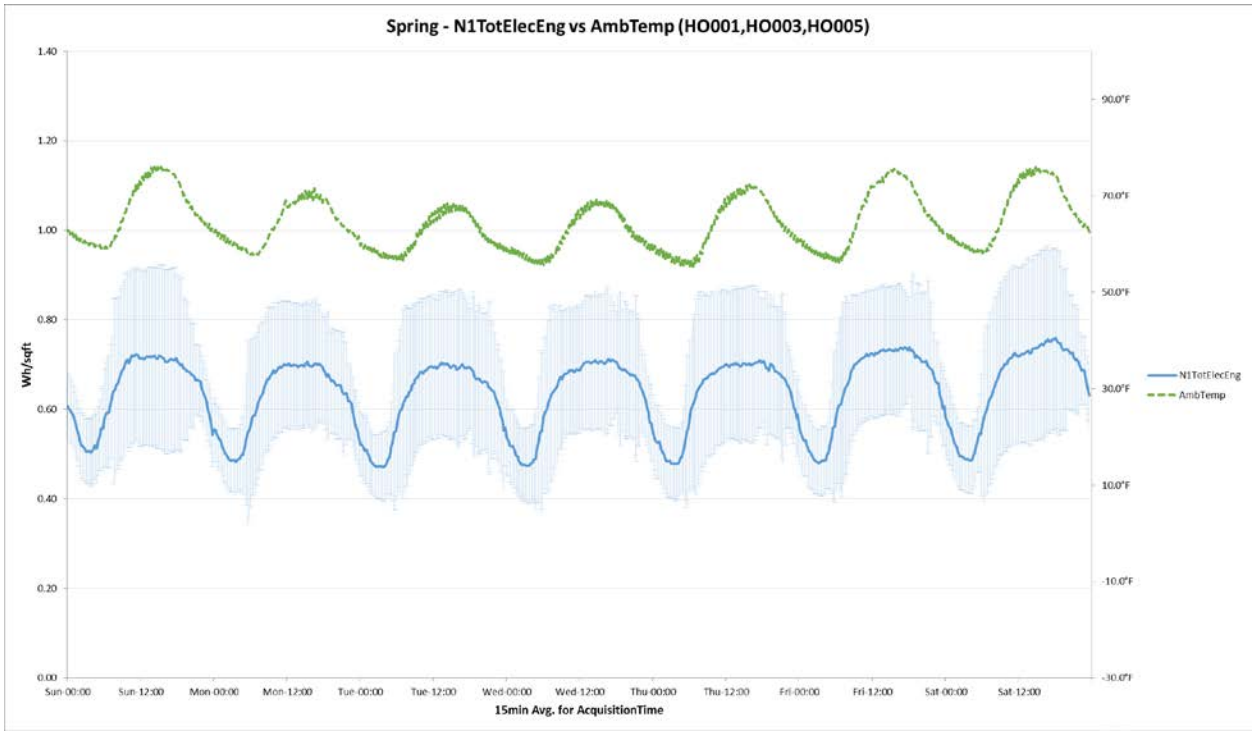


Figure 4-10: Hotel Summer - 15-minute energy intensity and ambient temp versus time

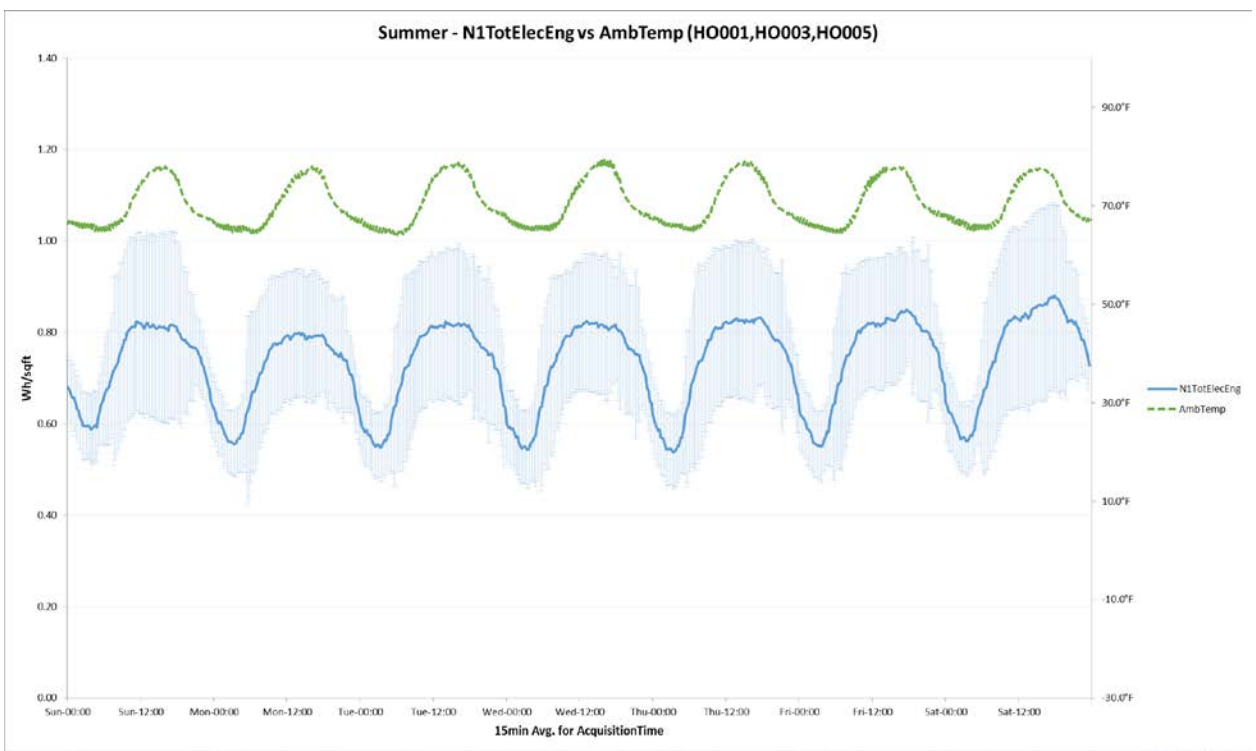


Figure 4-11: Hotel Fall - 15-minute energy intensity and ambient temp versus time

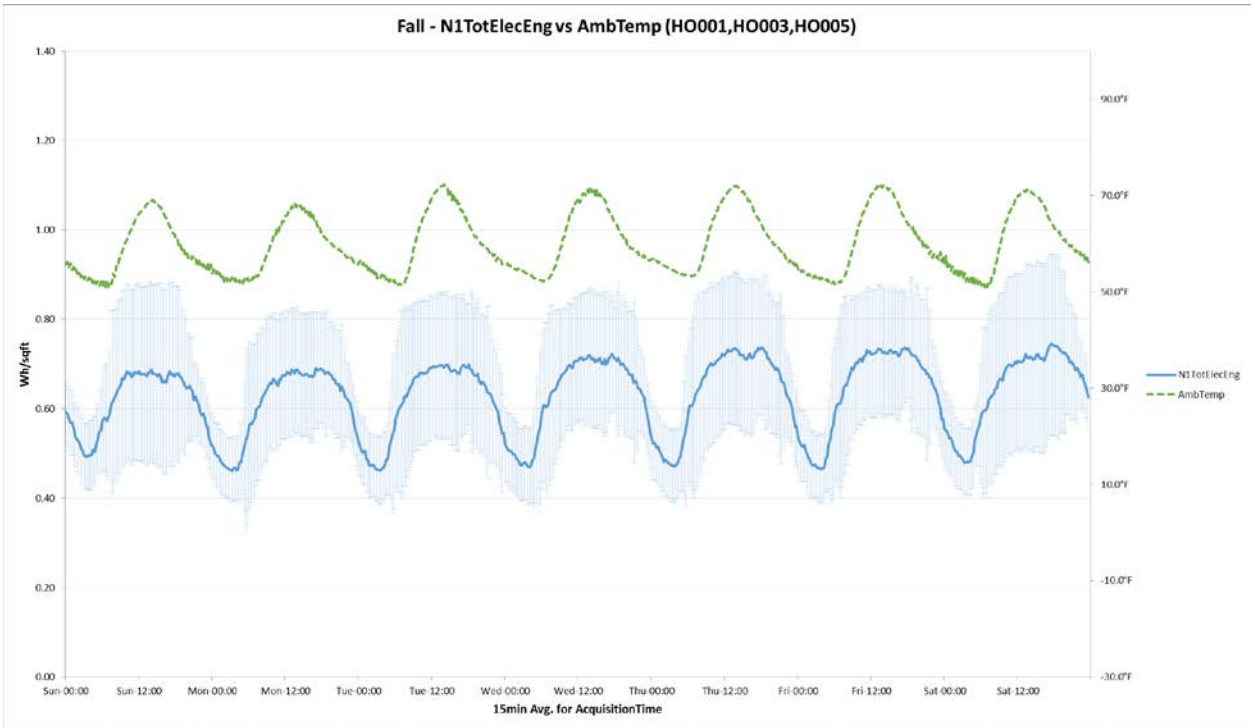
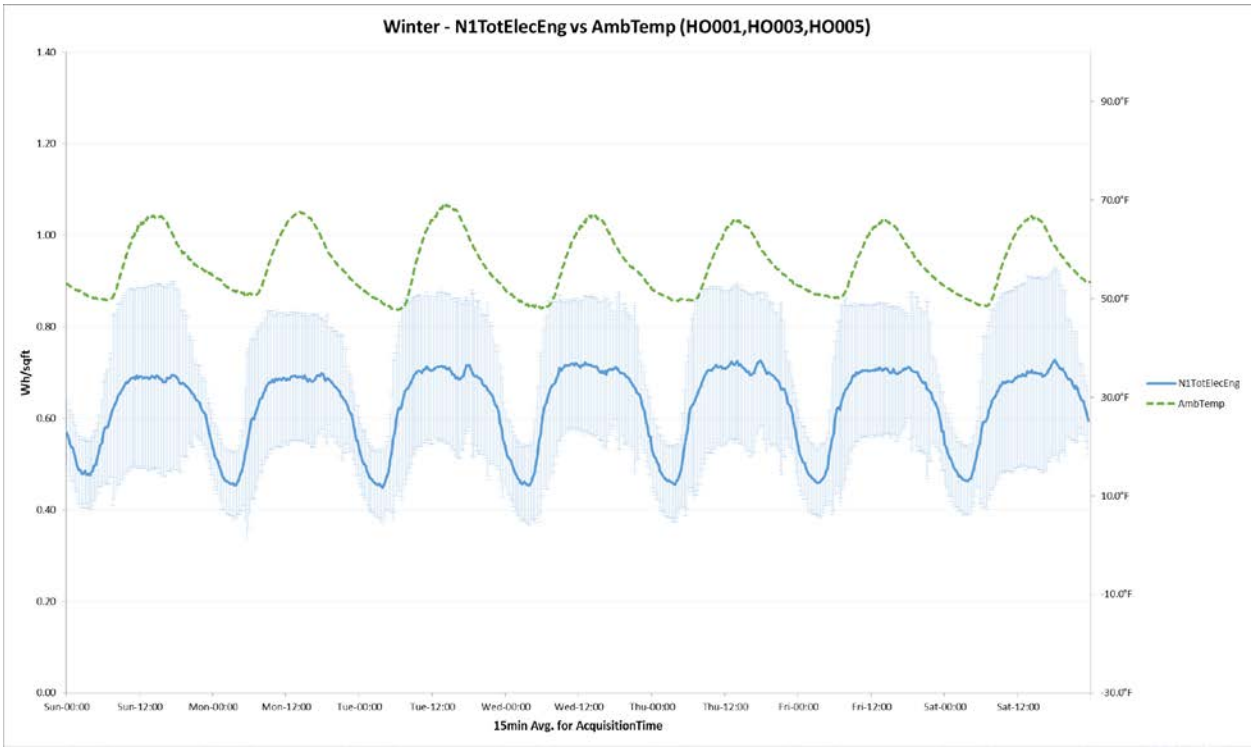


Figure 4-12: Hotel Winter - 15-minute energy intensity and ambient temp versus time



Figures 4-13 through 4-16 represent the weekly variation of the electric energy intensity for food/grocery facilities (FG) for Spring, Summer, Fall, and Winter respectively. The figures show the average intensity as the bold line as well as the 1-standard deviation range of values for the intensity. Also shown for reference is the average ambient temperature for each of these typical seasonal weeks. Given their 24/7 nature, there isn't a work-week per se. The consumption pattern is quite similar throughout the week with virtually no discernible variation weekday and weekend. Daily variations are as expected effectively representing the operating hours of the facility from nominally 6-7 am to 10 pm. There is a bit more noise in the data for energy intensity associated with the high and essentially random operation of the chiller systems for the facilities.

Important observations include the following key points:

- The minimum values are quite high, on the order of 0.75 – 0.9 watt-hr/sq-ft; on the order of the peak values for commercial office buildings. A further detailed review of the data is needed to explain the counter-intuitive minimum for the "spring" being greater than the other three seasons; the temperatures are consistent with the spring and summer seasons. Peak loads are on the order of 1.2 – 1.4 watt-hr/sq-ft and again seem to show a spring/summer load increase as compared to the fall/winter. This base load represents the nominal 24/7 nature of the need to maintain the refrigeration for food preservation.
- There is a sharp and distinct morning "start" of the day representing the lighting for the store.
- The constant increase in energy intensity for the day suggests some ambient heat soak into the facility and the need to increase refrigeration and some (albeit small as seen in the measured data) HVAC load. The energy intensity is effectively at its peak just before the evening shutdown and turning off the lights.
- The great increase in load/energy intensity associated with the hours of operation and effectively the store lighting suggests that great strides could be made in energy savings through efficient lighting retrofits, passive skylighting, and/or active control of lighting. This must though be balanced against the need for good and "attractive" lighting for consumers.

The implications of these variations in site and seasonal energy loads are discussed further in Chapter 5, with regard to potential application of CHP in these location types.

Figure 4-13: Food/Grocery Spring - 15-minute energy intensity and ambient temp versus time

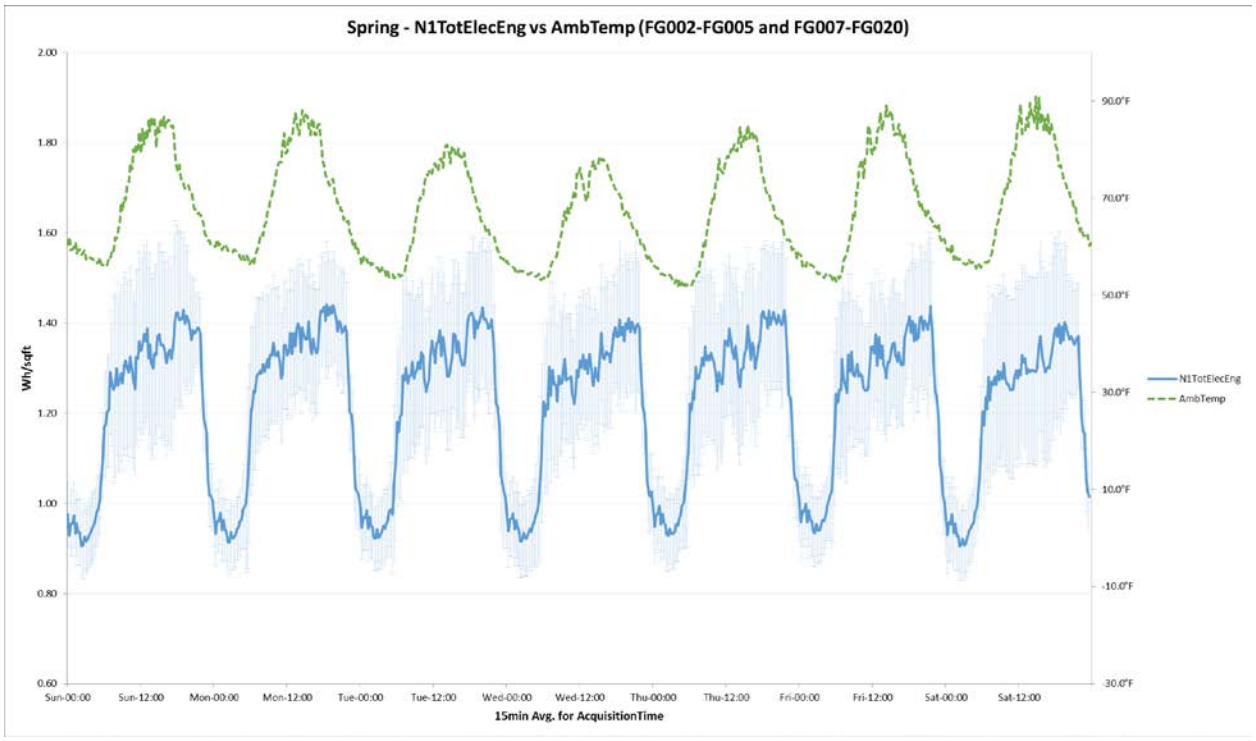


Figure 4-14: Food/Grocery Summer - 15-minute energy intensity and ambient temp versus time

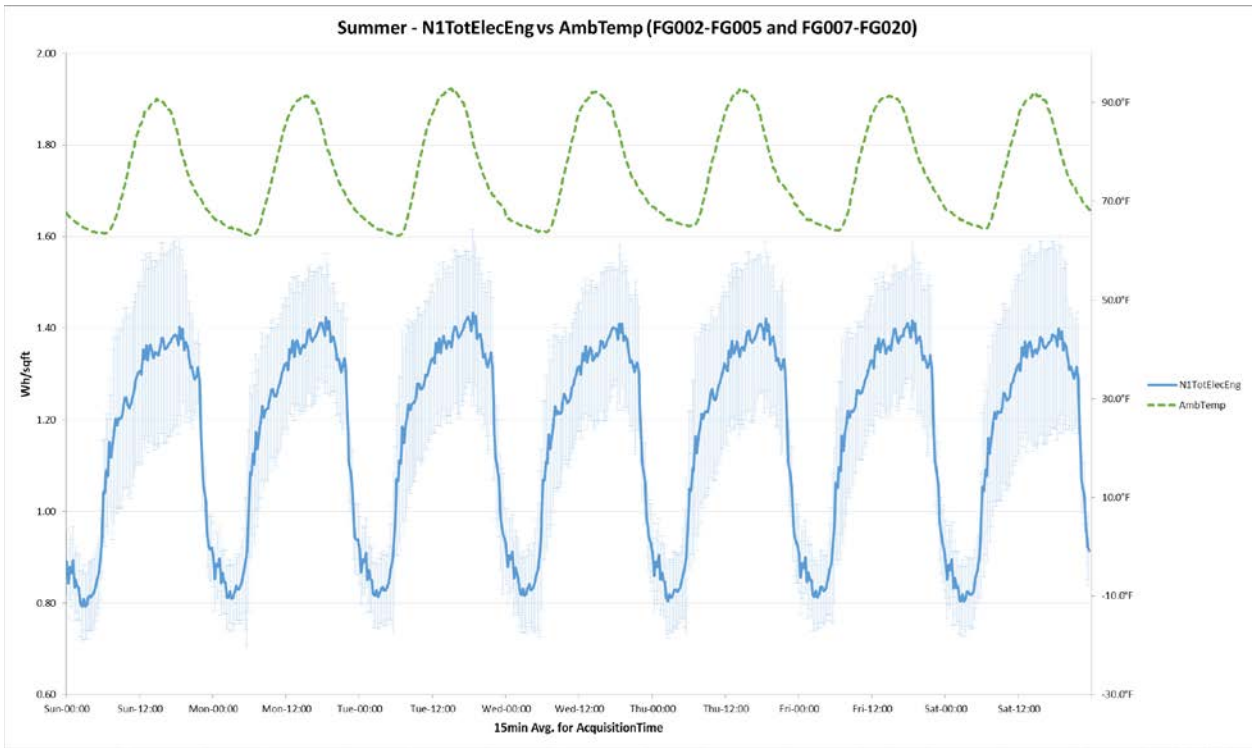


Figure 4-15: Food/Grocery Fall - 15-minute energy intensity and ambient temp versus time

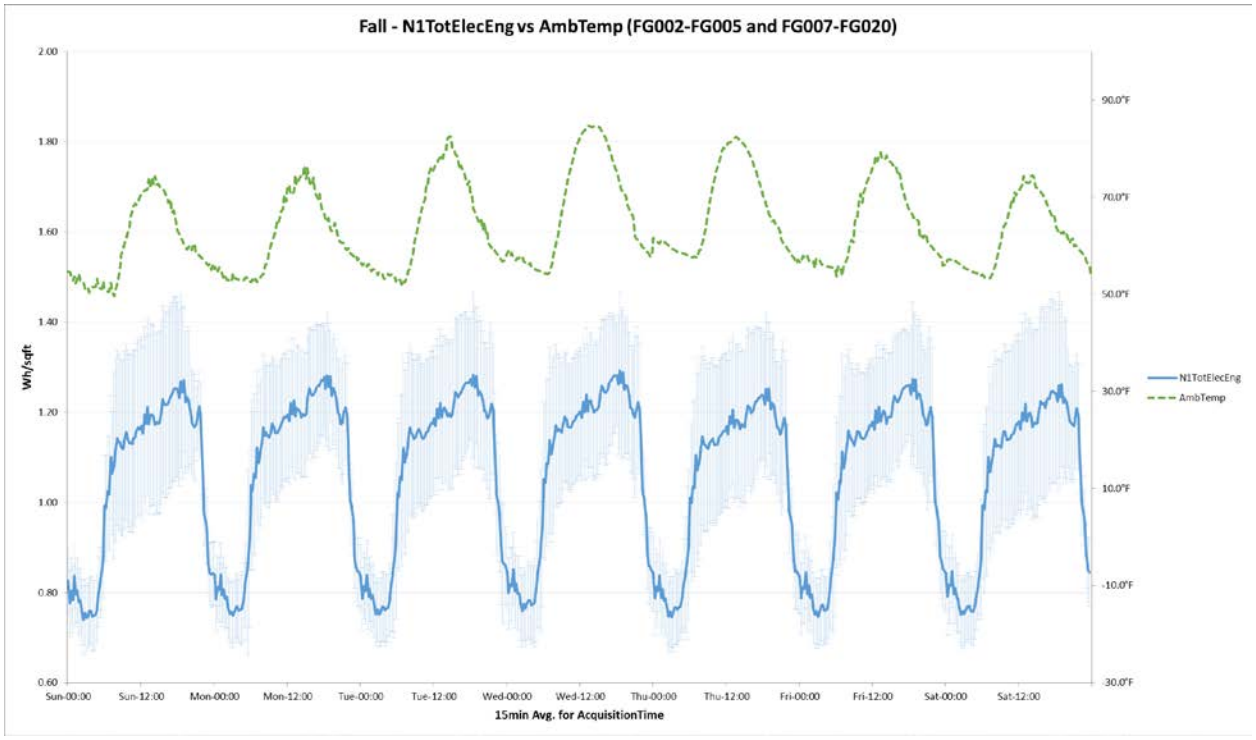
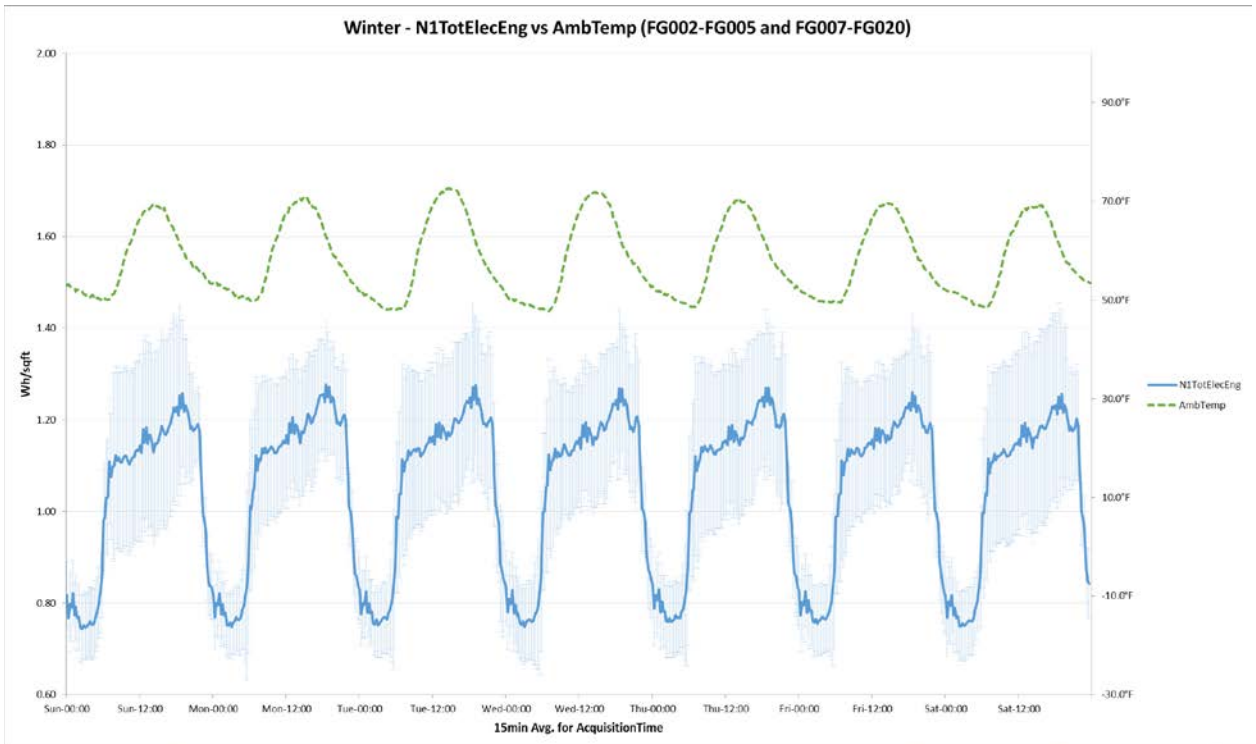


Figure 4-16: Food/Grocery Winter - 15-minute energy intensity and ambient temp versus time



CHAPTER 5:
Modeling Results and CHP Sizing/Performance Assessment

5.1 Introduction

This chapter further examines the building energy data described in Chapter 4. The results are compared with other data sources, and an analysis is presented with regard to potential CHP system applicability and sizing for these location types.

5.2 Comparison of Model Results with Other Data

One goal of this effort was to compare measured building data for a wide range of facilities with results that could be obtained from computer simulation models. The gathering of data from utilities and/or the instrumentation of a facility with meters for energy related parameters of interest is an intensive effort. Further, for a facility that is instrumented, follow-on effort is needed at intervals necessary to retrieve data for archiving or processing. The ability to model a building with a computer simulation can provide a great savings in time and money if the model can provide reasonable indication of energy consumption if not a highly accurate simulation. To that end, this program sought to compare the available data gathered in the CEC Energy Monitoring program describe in the section above with a computer simulation code.

There are a wide variety of energy simulation codes available. Perhaps the best-known code is eQuest that combines the calculation "engine" of the DOE-2 software package with a user friendly interface. eQuest provides the user to develop very detailed models of a building with customized construction, operation, and control strategies. It also provides a building "Wizard" to run simulations effectively generic buildings with some limited degree of customization (such as upgrades to windows, energy controls, etc.). For the comparison undertaken, the building Wizard approach was applied to a generic building representing many of the sectors in the Energy Monitoring Program.

The generic building results were then compared to the normalized average building performance as measured in each sector. Since the sector average building represents a wide array of building styles, construction, floor plans, orientation, operational protocols, and environmental conditions, it would be impossible to develop a representative model for the sector. Rather, an evaluation of the generic building for each of these sectors as provided in the eQuest "wizard" should provide a reasonable representation for the buildings and effectively assess the eQuest assumptions for each of the building types.

The eQuest modeling was performed for the following building types/sectors with no significant energy efficiency measures (an option) and the following characteristics.

1. Office building: 10 stories, 10,000 sq-ft per floor (100,000 sq ft total), square plan form
2. Hospital: 5 stories, 100,000 sq-ft per floor, (500,000 sq-ft), square plan form

3. Hotel: 20 stories, 20 rooms per floor, 10,000 sq ft per floor (200,000 sq-ft total), square plan form

Note that an analysis for a "generic" food/grocery facility was not included, so a refrigeration load for the facility that was representative of a real system was not developed or defined. Note also, that all buildings were located in Irvine, CA for the simulation weather/temperature parameters.

5.3 Generic Model versus Average Data

Each of the three "generic" building parameters was used in conjunction with the eQuest Wizard feature to develop a one-year performance prediction. The results were then broken into the seasonal quarters consistent with the prior definitions (e.g. April- June = Spring, July – Sept = Summer, etc). The results of the model versus the measured data are shown in Table 5-1.

The results reveal a general and significant under prediction of the energy intensity across the board. The hospital/health prediction was closest in agreement but eQuest Wizard was still under predicted by 50 percent the actual measured data. Not knowing the specific assumptions within the model, it is difficult to pinpoint a specific reason. There seems to be a general under prediction of the loads, both during the evening and during the day.

For example in the case of hotels, eQuest Wizard predicts a minimum energy intensity of 0.34 watt-hr/sq-ft for a hotel whereas our data suggests the minimum of approx. 0.5 watt-hr/sq-ft per 15 minute interval = 2.0 watt-hr/sq-ft, a factor of 5x difference (Recall at the introduction to this section, the ordinate was defined the energy intensity per 15 minute interval). For the maximum energy intensity, eQuest predicts approx. 2.2 watt-hr/sq-ft for the summer whereas the measured data is 3.2 watt-hr/sq-ft (0.8 watt-hr/sq-ft per 15 minute interval x 4).

This same under-prediction same issue occurs with all of the sectors. Not only does eQuest under predict the values, it seems to not predict the profile well either. Further, it does not seem to be an adjustable parameter within eQuest Wizard. Perhaps some deeper levels of eQuest would allow for some additional customization of load and/or load profiles but that would necessitate load measurement, at least spot checks of minimums and maximums. One must then ask, "Once measurements are necessary for calibration of the model results, does the model itself become redundant?" An accurate model does certainly provide an opportunity to evaluate deviations from the current building state (e.g. energy efficiency measures, distributed generation, etc). Further, if there more specific building data can be incorporated in the model (as will be shown in the next section) rather than something too "generic", the results may be more accurate. Nevertheless, this exercise suggests that a blind "prediction" of a facility's energy needs can be significantly under-estimated by a model.

Table 5-1: Comparison of measured versus generic model energy intensity

Building Type	Electric Energy Intensity					
Source/study		**CEUS**	**UCI - CEC**			
		kwh /ft^2/yr	kwh/ft^2/yr (Standard Deviation)			
			Spring	Summer	Fall	Winter
Commercial Office-large (>30K ft^2)	Measured	17.70	17.8 (5.3)	19.1 (6.0)	17.6 (5.6)	17.15 (4.9)
	eQuest Prediction	-	8.68	9.74	8.03	7.45
	Deviation [%]	-	105	96	119	130
Hospital/Health	Measured	19.61	28.4 (7.7)	34.9 (9.2)	26.6 (7.5)	29.4 (8.4)
	eQuest Prediction	-	19.2	20.8	18.4	17.4
	Deviation [%]	-	48	68	45	69
Hotel	Measured	12.13	22.3 (2.5)	25.6 (2.6)	22.0 (2.7)	22.0 (1.8)
	eQuest Prediction	-	7.79	9.4	7.1	6.4
	Deviation [%]	-	185	172	210	244

5.4 Specific Model versus Specific Building Performance

The aforementioned modeling efforts with e-Quest were focused on the average results of the monitoring efforts for multiple facilities in the sector as compared to a generic eQuest model. With the extensive "averaging" associated with the diverse nature of the facilities in the sector and the simplification assumptions associated with the e-Quest modeling, the agreement between the sectors and the model are quite poor. Further investigation in the eQuest Wizard feature would be required to better understand the shortcomings of this as an initial assessment tool.

To assess the specific agreement or lack of agreement between the actual measured data and the results of an eQuest simulation of a specific building, commercial office #6 structure was modeled and the results compared. This particular building is one of three sister buildings located in Irvine, CA. The building is a regular rectangular prism of square plan form (i.e., 145 ft per side) and 19 stories tall for 21,000 sq-ft per floor and 400,000 sq-ft total. The facility was built in 1990 and is assumed to have nominally common energy measures employed at the time.

The eQuest model was developed, adjusted, and customized to the extent of our knowledge to match the known characteristics of the building. Unfortunately, the specific information on the building construction and energy measures employed was not gathered as part of the original CEC study from which the measured data was obtained. As such, specific information on the building control strategies, the building construction (such as fenestration and insulation), nor on the occupancy patterns for the building were unavailable, and eQuest parameters relied upon its default conditions. One important note for this facility is that it (and its sister buildings) utilize electric energy for the building heat rather than natural gas boiler or furnace. As such, the heating load is part of the building electric load and included in the measured electric energy. For the eQuest model results, the predicted heating load (which is included as a natural gas load in btu/hr) is converted to "kW" and added to the electric load. The eQuest predicted heating load is relatively small and only appears in the morning "warm-up" in the fall and winter.

The results of the eQuest model versus the measured data are presented Figures 5-1 through 5-4 as a weekday/business day average for each of the seasons. For all cases the load profile shape is similar if not slightly broader and shifted to a later time for the actual versus the modeled. For the Spring and Summer, the peak loads during the middle of the day are closely approximated, much closer that perhaps the normalized averages in Table 5-1 would suggest. However, fall and winter peak loads are not too close (actual about 66 percent higher than the model predictions). Further, the actual overnight periods are significantly higher than modeled. It is easy to speculate that the overnight loads (a consistent 500 kW regardless of season) may be attributable to a "data center" or other 24/7 type of base load. Since the measured data project did not conduct a survey of the actual building uses and internal loads, there would be no way to a priori include these loads as part of the eQuest model.

Interestingly the overnight load does not appear to be a scalar addition to the loads across the board; that is the daytime loads are not consistently 500 kW greater than the modeled load suggesting that the eQuest model does account for the overnight load in some manner but assumes that this load is shut down at the end of the business day resulting in very low modeled overnight loads. Also note that the Fall and Winter models show the small spike in modeled load associated with the electric heating. It is relatively small and effectively is not visible in the Spring and Summer graphs. In the measured data, the spike may be there but is likely overwhelmed by the other buildings loads and perhaps, as a result of its multitenant nature, the initial morning load and evening load is a softer than the model prediction. This is revealed in the later and slightly shallower slope of the energy curve in both morning and afternoon.

Figure 5-1: Results for Case CO006 Spring

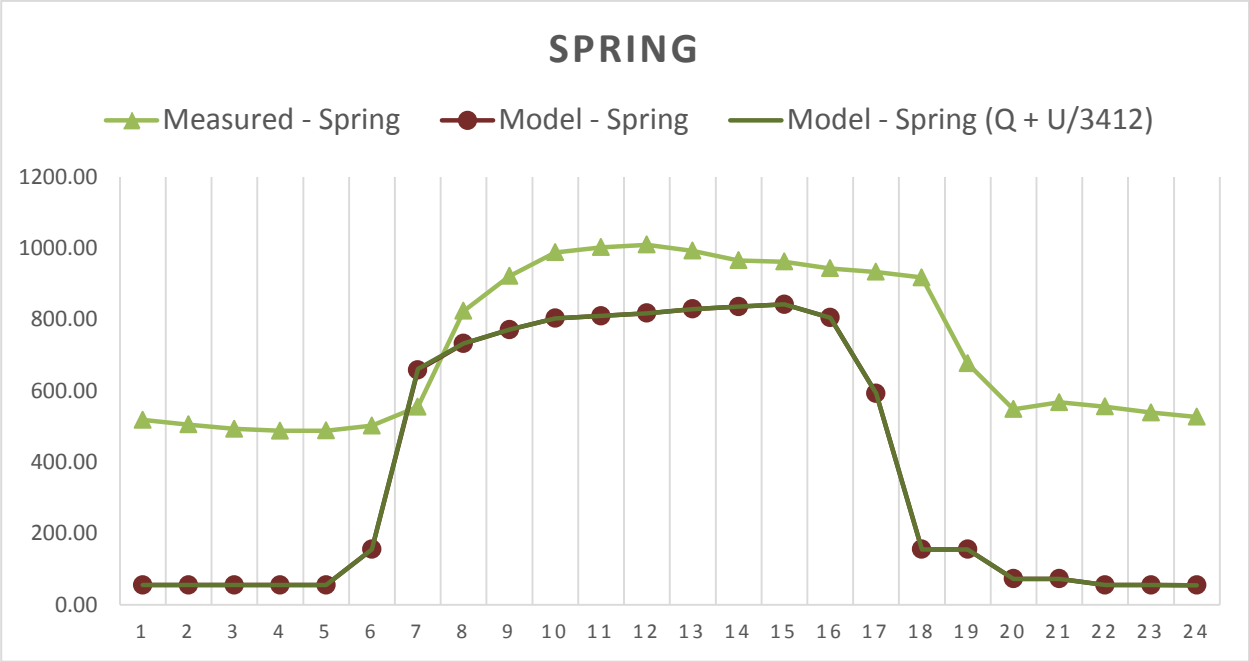


Figure 5-2: Results for Case CO006 Summer

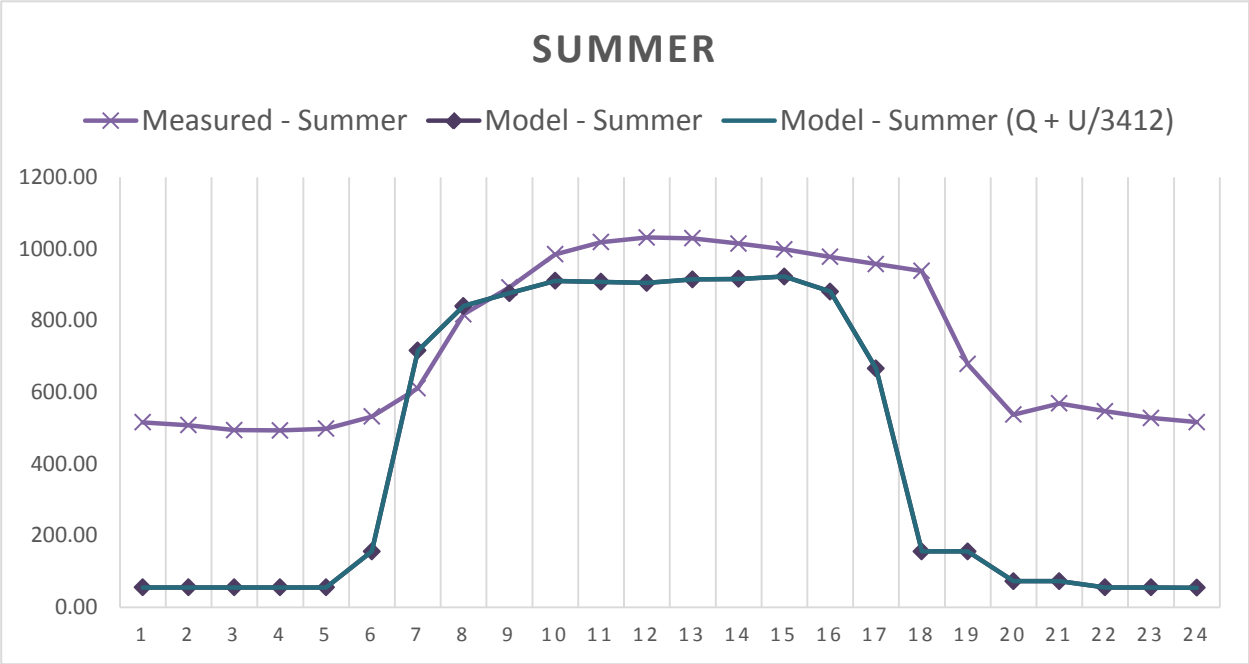


Figure 5-3: Results for Case CO006 Fall

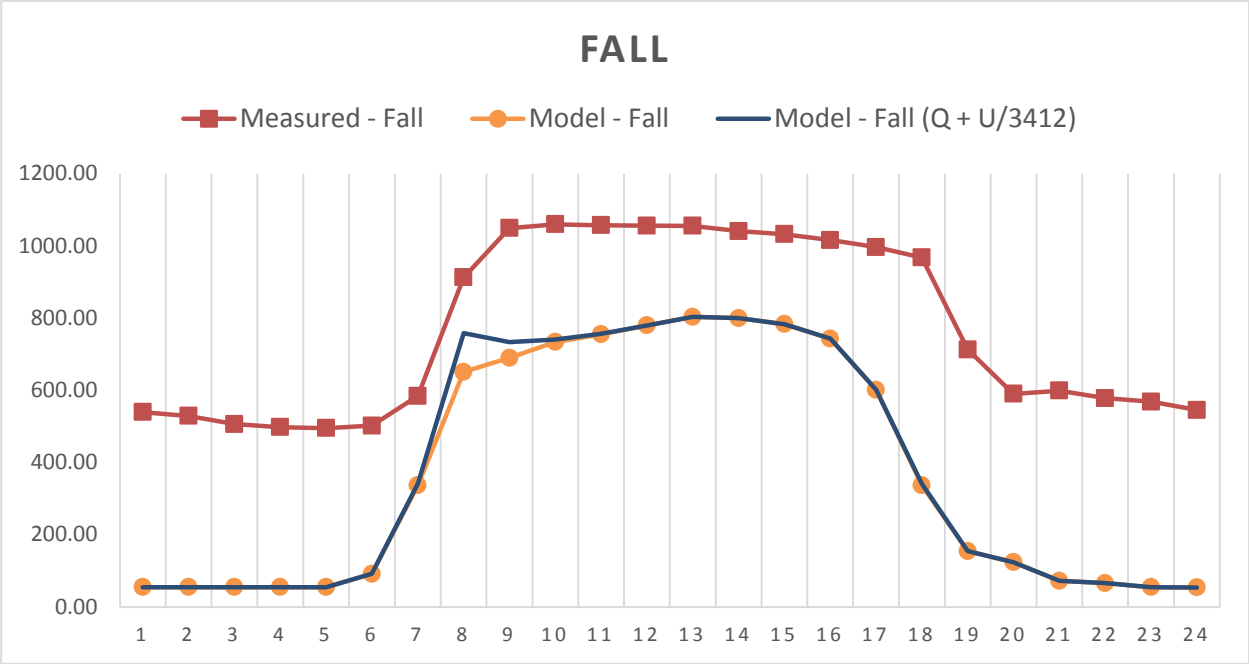
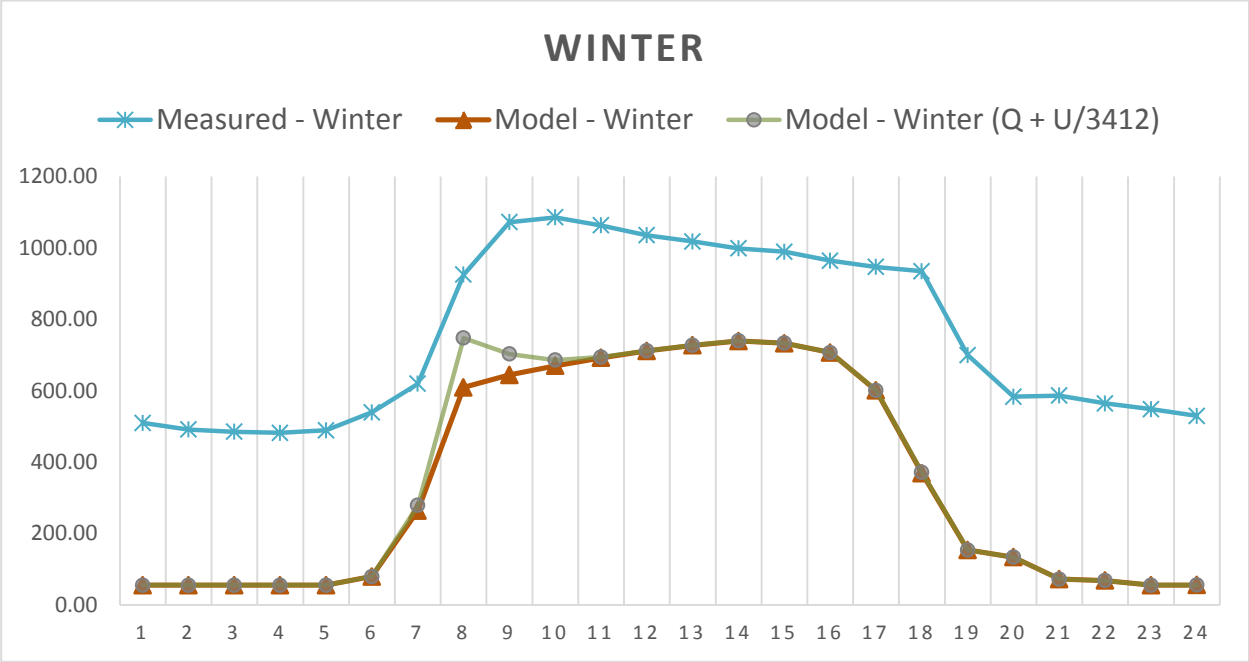


Figure 5-4: Results for Case CO006 Winter



5.5 CHP Equipment Sizing / Performance Assessment

It is well understood and accepted that for the maximum overall thermal efficiency of the CHP system; the maximum amount of waste heat must be captured and utilized in a beneficial manner. While not always the case especially considering the changes to rules that allow back feeding to the grid and even "feed-in-tariffs", the general guideline of sizing the CHP system for the "heat load" application, whether that be a heating or a thermal driven cooling system or something else, and consider the electric power as an incidental benefit. The guiding principle is that the majority of the input fuel heating value exits the prime mover as "waste" and as such, maximizing this utilization inevitably maximizes the overall efficiency and minimizes the operating costs (minimizes fuel use).

During the period of the monitoring program, (2007 – 2009 time frame), CHP was certainly not a new technology. However, there was still a general reluctance to embrace the technology. The program initially attempted to identify and engage facilities that utilized CHP in one form or another for roughly half of the total sites monitored. However, when all was established, there were only four sites that had CHP. Of these, three were systems installed to meet only a portion of the overall electrical and thermal loads for the facility, ostensibly as a "beta" test of the system both at the equipment evaluation level and the overall system applicability at the facility with a vision to perhaps a greater, wider spread deployment at the facility. The fourth site, the University of California Davis Medical Center (hospital) system was designed and optimized to provide vast majority of the facilities electric and heating/cooling/steam needs.

5.6 South Coast Air Quality Management District (SCAQMD) Headquarters-Diamond Bar, California

The SCAQMD headquarters CHP installation was primarily developed to assess and monitor the development of DG/CHP systems and their possible implications relative to South Coast Air Basin air quality. The installation consists one installation of four 60-kW Capstone microturbines and a waste heat recovery system, installed in the 2001/2002 time frame and a second installation of three later model Capstone "iCHP" 65 kW units (microturbines with integrated waste heat recovery systems rather than separate heat recovery systems) installed in the 2007 time frame. The system as a whole had a total nameplate capacity of approximately 435 kW and perhaps 2.8 MMbtu/hr of waste heat recovery.

For comparison, the AQMD headquarters building has a nominal average meter electric power demand of 1 MW with a minimum of 500 kW and a summer maximum of approximately 2 MW. Thermal loads are address by boilers providing a nameplate total of 4.8 MMbtu and electric chillers with a name plate total of 1540 tons. The installed DG/CHP system had the capability of providing a significant contribution to the facility's electric and thermal load needs. However, the actual installation was not well designed to meet these needs (i.e. remote location and long runs for the hot water resulting in significant heat loss) but rather as a showcase/demonstration/evaluation facility.

Seasonal operational data for the AQMD installations are presented below in Figures 5-5 through 5-12. The four-turbine site had net electric metering on each turbine. Note too that for

each pair of turbines, one of the two had the additional parasitic load of approximately 5 kW associated with the natural gas compressor (one compressor for each turbine pair, #1 and #3). In the graphs, the four-turbine installation has each turbine listed individually while the three-turbine site is listed as "3 MTG total".

For the three-turbine installation, a single cumulative net electric meter is installed at the point of common connection. Further, the three-turbine installation has three individual compressors, one for each turbine. Hence, the presented energy output is a cumulative net.

The systems have a nominal operational schedule of 8:00 am to 10:00 or 11:00 pm (depending upon the system and the time of year) Monday – Friday, no operation on Saturday or Sunday. The plots shown in the figures do not discern between weekend and weekdays; hence, on average there would be an expected reduction of the average energy output of 28.6 percent (2/7th of the week). For a nominal rated 60-kW turbine (as is the case for the 4-MTG installation), the expected gross maximum energy during operation would be:

$$60/4 \times (1-.286) = 10.7 \text{ kW-hr}$$

For the three 65-kW microturbine system, a similar calculation of the maximum gross output is:

$$(65*3)/4 * (1-.286) = 34.8 \text{ kW-hr}$$

Using these two maximum power benchmarks, it is possible to make some assessments of the operation of the turbines during the time periods presented. Note that the efficiency measurements are not affected by this averaging; the efficiency as presented is representative of the actual system operation and does not need to be tempered with a fraction of non-operating period.

The figures indicate that the nominal 8am-10pm operation was not always maintained; they show specifically the turbine #1 of the four-turbine system was often operated during off hours. The power output of the individual turbines and overall efficiency variations of the four-turbine system are indicative of the age and operational hours of the system. Note that when turbine #1 was operating by itself in the "off" hours, the overall efficiency was greater than 50 percent and approaches 70 percent, but at the point the other turbines came on line, the overall efficiency decreased to between 40 percent and 50 percent. This would indicate that either the operation of the other turbines, the heat exchanger for the #3 and #4 turbines, or a combination of the two comes into play.

For the three-turbine installation, the power output suggests some operational problems during the period from Oct 2008 to March 2009 (Figure 5-5 through Figure 5-8) owing to the relatively low energy production. The suggested operation is approximately 50 percent of the allocated time, shown by an energy output of 16-17 kW-hr versus the expected max gross number of 34.8 kW-hr. However, when operating, the overall system efficiency is on the order of 50 percent to 70 percent.

For both installations, energy output is reduced in the hotter seasons as expected due to the known turbine performance reductions with higher ambient temperatures. The overall thermal

efficiency is similarly reduced in the hotter months but primarily due to the reduced need for hot water for heating and not as a result of significant reductions in the efficiency of the turbine operation. One anomaly in the efficiency is in the July to September (summer) time frame shown in Figure 5-12. The extraordinarily high efficiency is believed to be a result of the increased air conditioning load for the building; with increased air conditioning demand, the need for hot water would also increase to provide the necessary local reheat of the conditioned air.

Figure 5-5: AQMD MTG Installation - Typical Energy Profile from Oct-Dec 2008

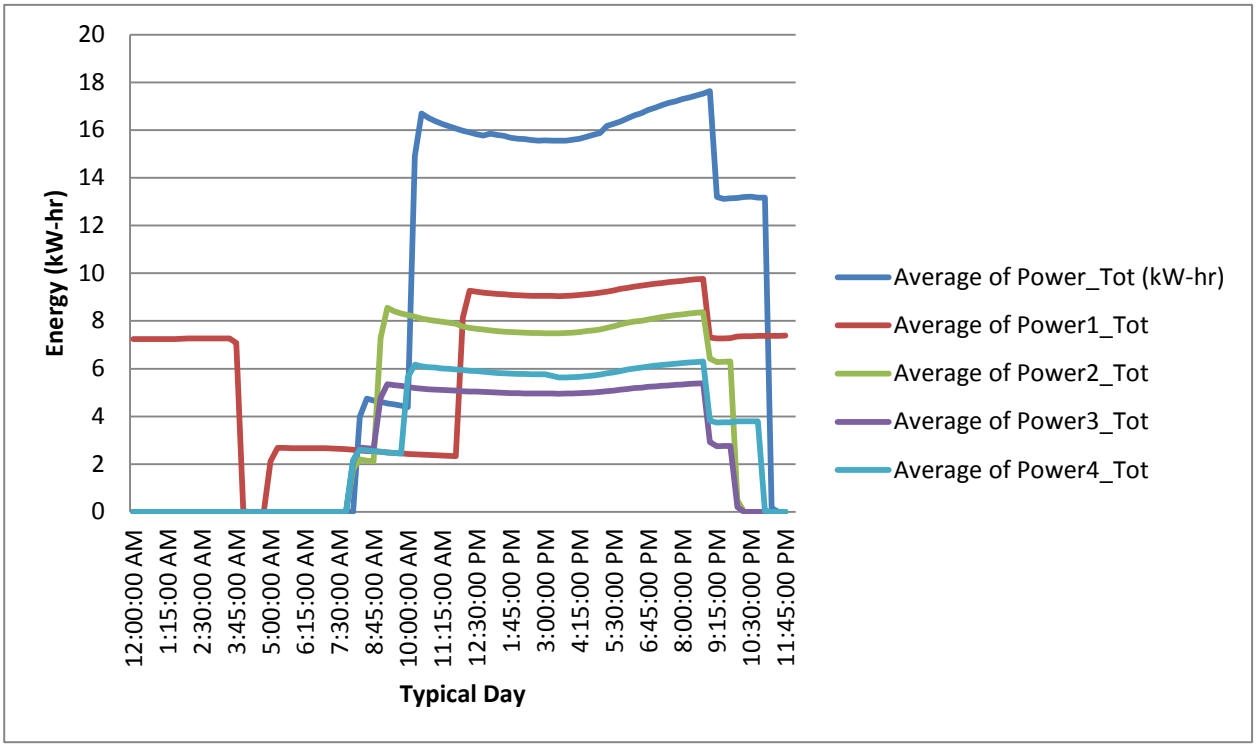


Figure 5-6: AQMD MTG Installation - Overall Thermal Efficiency (HHV) Profile from Oct-Dec 2008

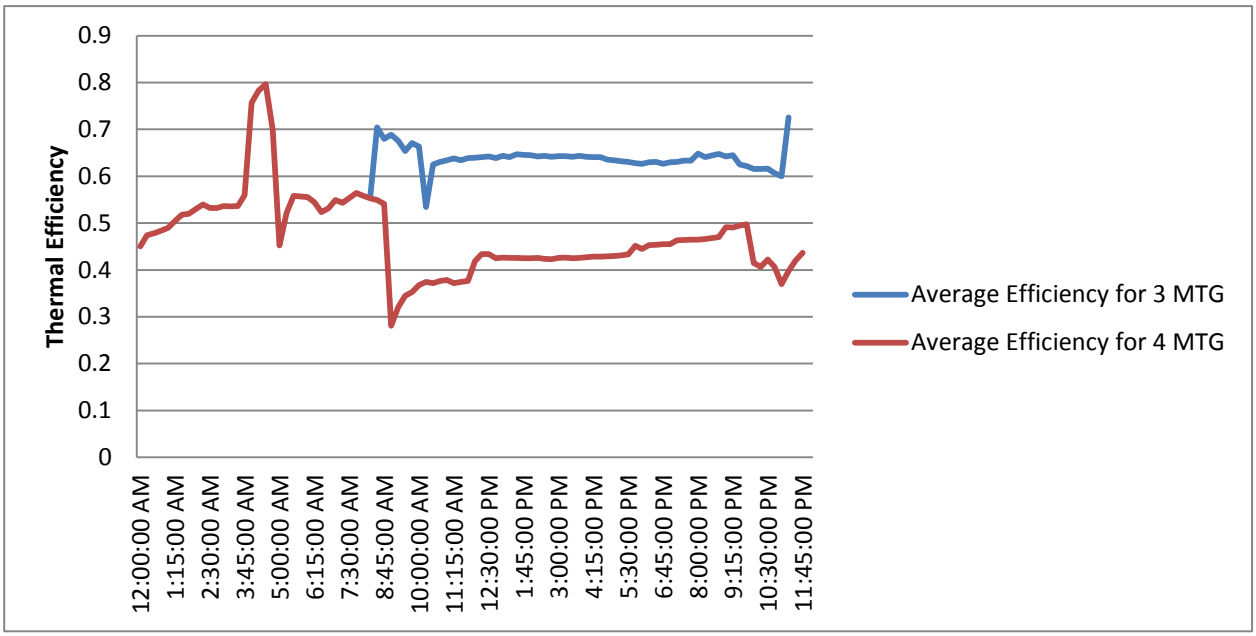


Figure 5-7: AQMD MTG Installation - Typical Energy Profile from Jan – March 2009

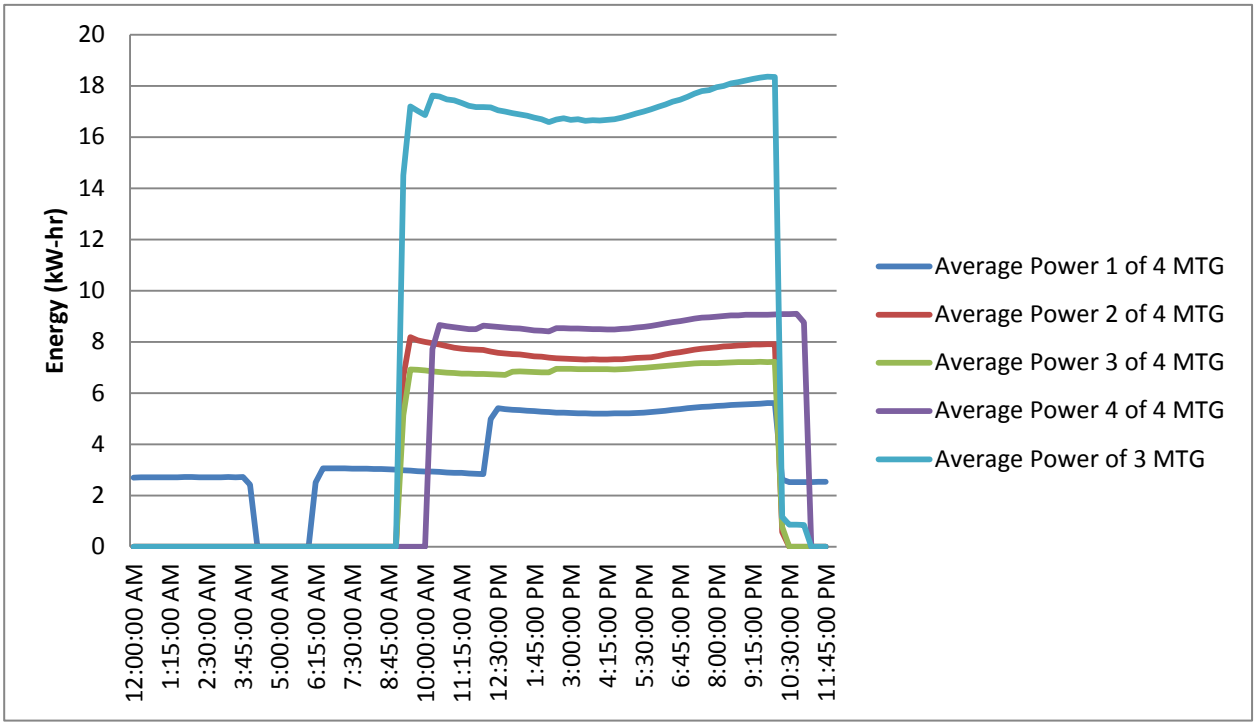


Figure 5-8: AQMD MTG Installation - Overall Thermal Efficiency (HHV) Profile from Jan – March 2009

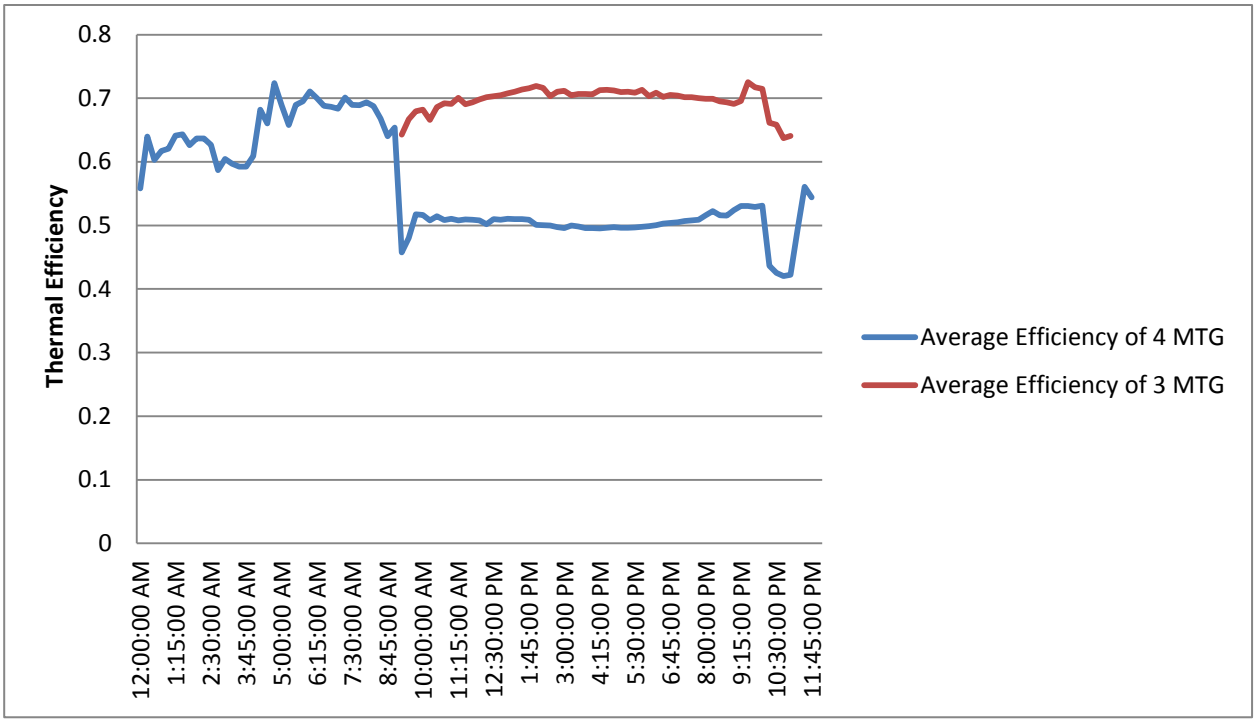


Figure 5-9: AQMD MTG Installation - Typical Energy Profile from April – June 2009

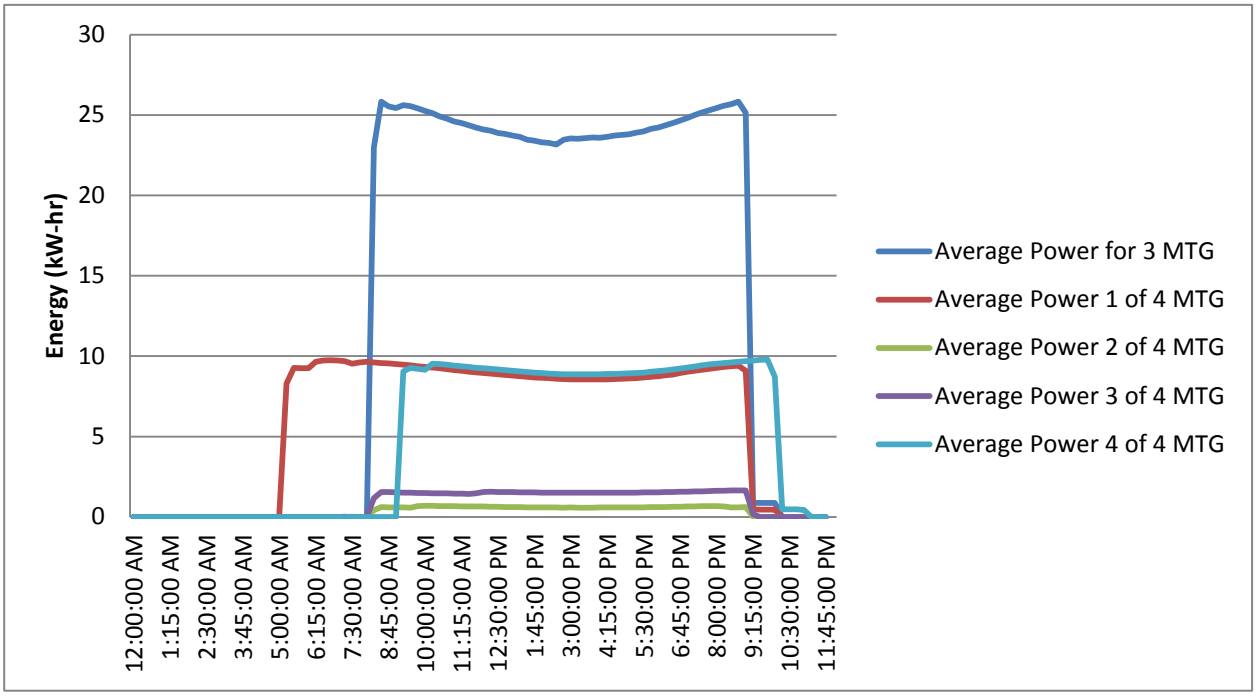


Figure 5-10: AQMD MTG Installation - Overall Thermal Efficiency (HHV) Profile from April – June 2009

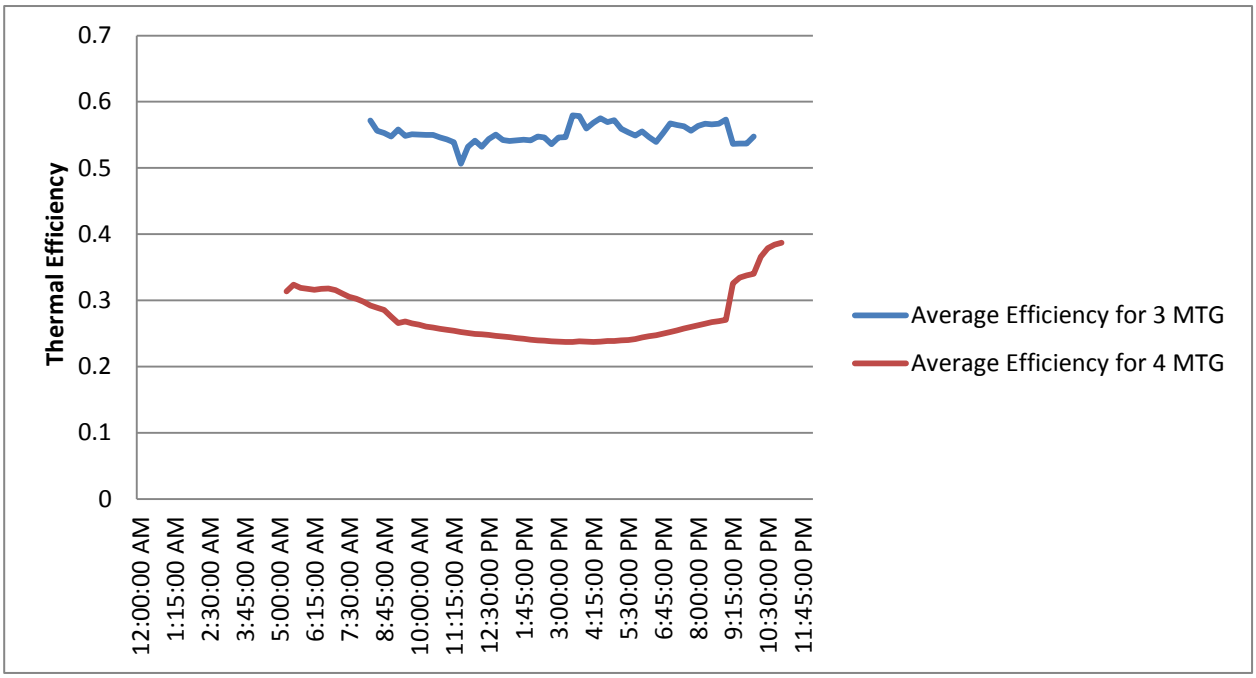


Figure 5-11: AQMD MTG Installation - Typical Energy Profile from July - Sept 2009

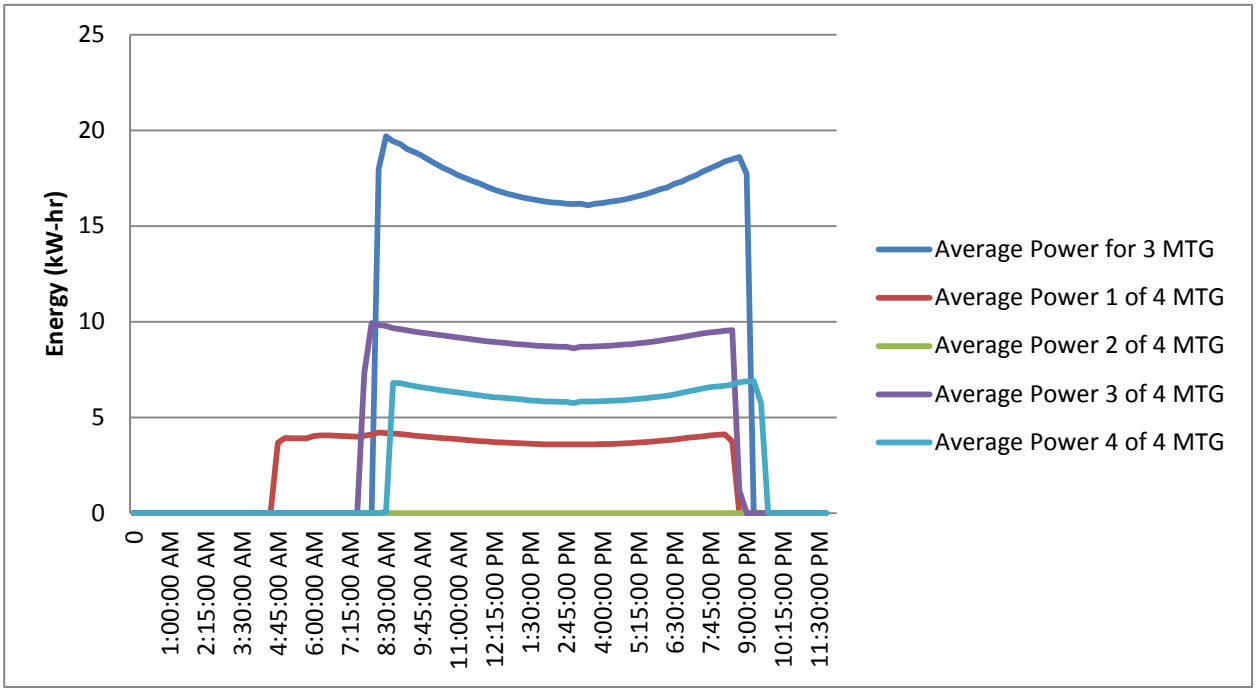
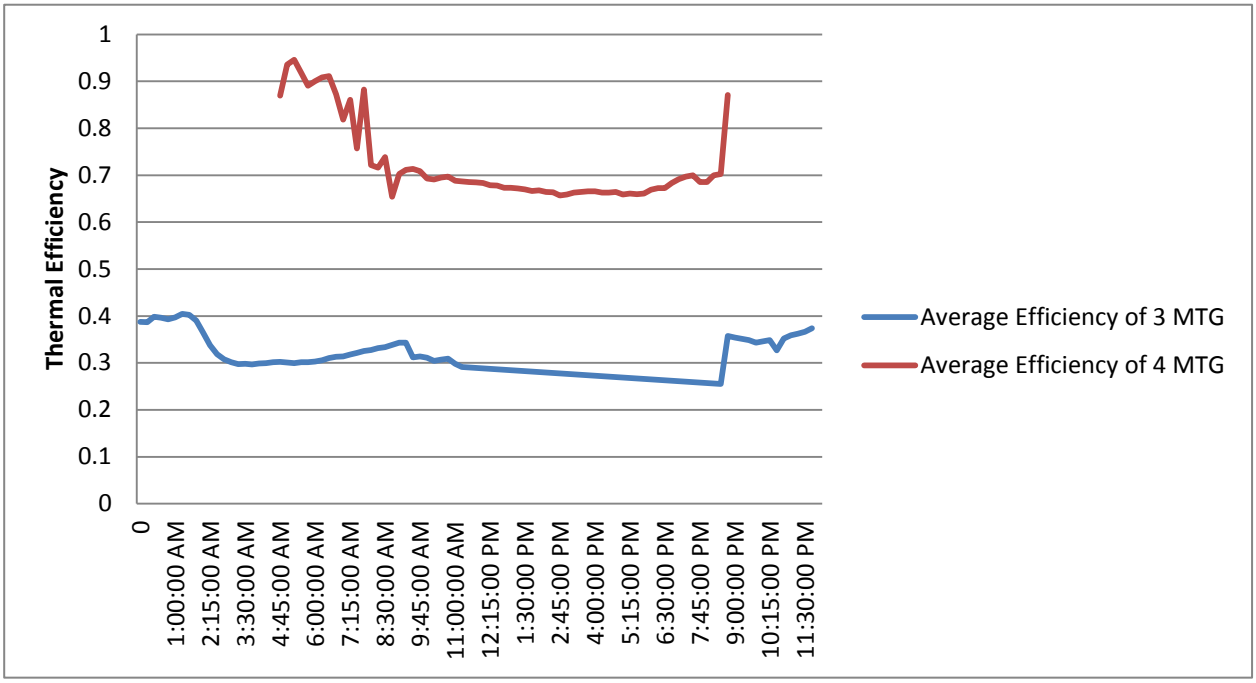


Figure 5-12: AQMD MTG Installation - Overall Thermal Efficiency (HHV) Profile from July - Sept 2009



The AQMD has a nominal average meter electric power demand of 1 MW with a minimum of 500 kW and summer maximums of approximately 2 MW. The combined output of the turbines based upon a name plate of 435 kW and a measured averaged output of approx 225 kW during the nominal operating period suggests that the turbines meet approximately 20 percent of the facilities average electric power requirements.

5.7 California State University, Northridge (CSUN)

The California State University at Northridge has demonstrated an affinity for advanced energy efficiency systems and distributed generation systems; in no small part due to the need for a wide spread campus rebuild effort after damage from the 1994 Northridge earthquake. In 2001, CSUN installed an array of seven, 30 kW Capstone microturbines with waste heat recovery in their central plant to provide electric power and effectively take one of their boilers out of service (note that at the time of the energy monitoring program, the 30-kW array was out of service). CSUN also has a large solar PV system (700 kW total) in the form of parking lot car shades. Finally, CSUN was an early adopter of molten carbonate fuel cell technology, installing a 1 MW nameplate Fuel Cell Energy System in the 2006/2007 timeframe.

The primary purpose of the fuel cell was to provide electric power for a remote central plant, feeding power to the campus grid but effectively using the electric power to run the electric chillers at the remote central plant. The system was also designed to capture the waste heat in the exhaust through a then unique condensing heat recovery system. Finally, and again a unique for the time, the cooled CO2-rich exhaust gas was directed to an adjacent "rain forest" greenhouse to assess the effects on plant growth and natural CO2 capture/sequestration. Even at 1 MW, the system provides only a small fraction of the campus electric and thermal loads, the former peaking at 15 MW during the summer.

The CSUN 1-MW molten carbonate fuel cell seasonal operation history is shown in Figures 5-23 through 5-29 for a 21-month period from April 2008 to Dec 2009. The presented data includes the electric power production from the fuel cell, the fuel to electric efficiency of the fuel cell based upon lower heating value of the fuel and the overall thermal efficiency of system (electric and thermal) based upon higher heating value of the fuel. The added measure of electric generation efficiency was included to help complete the data presentation. As noted above, CSUN incorporated both sensible and latent waste heat recovery from the exhaust stream. The complexity and ramifications associated with latent waste heat recovery resulted in numerous problems in the waste heat recovery, primarily heat exchanger corrosion and failure issues but also failure of monitoring equipment. These issues are shown in the overall thermal efficiency measurements for 2008 (Figure 5-15, 5-18, and 5-21).

The last quarter of 2008, the overall efficiency was essentially equivalent to the fuel to electric efficiency of the fuel cell, indicating little if any thermal recovery. The data for 2009 reflected the on-going issues with large periods of no heat recovery followed by periods of overall thermal efficiencies greatly exceeding 100 percent. Inaccuracies in the thermal monitoring equipment for the latter period are suspected to be the root cause of the latter. Due to the highly suspect thermal data for the system, the overall thermal efficiency for 2009 is not presented. Rather, the

fuel cell operation for the period of 2009 is detailed, providing both the energy output and the fuel cell thermal efficiency.

The progression of the commissioning process of the fuel cell system is evident in the increasing power production for the typical days for each season presented in Figures 5-13, 5-16, 5-19, 5-22, 5-26, and 5-28. Energy output increases from approximately 150 kWh (for each 15 minute interval) in the April-June 2008 interval to just less than 250 kWh in the Oct-Dec 2009 interval. The latter period suggests nearly 100 percent availability/operation based upon a 1 MW rating for the system. The specifics of the reduced energy production of the earlier intervals are not specifically known; however, based upon a nominal 1MW output for the system, one can estimate availability ranging from as low as 60 percent to approaching 100 percent.

The fuel to electric efficiency shows a very consistent trend for virtually all of the periods of roughly 40 percent based upon the lower heating value but increasing to better than 50 percent during the October to December 2009 interval. The progression suggests the facility was in a continual period of operational refinement and/or equipment upgrades the resulted in both the high electric energy output and high fuel to electric efficiency noted in the fourth quarter of 2009. Note too that the period represented by the third quarter of 2009 represented the lowest fuel to electric efficiency but with relatively high-energy output. This suggests a significant degradation of the system, perhaps the fuel cell stack itself, that hindered both energy output and the efficiency; a stack replacement during the late third quarter or early fourth quarter would explain the significant jump in efficiency and the improved energy output. However, there is no confirmation of the steps or actions on the part of Fuel Cell Energy or CSUN during this period of what actually occurred.

When operational, the overall thermal efficiency of the system was consistently 60 percent. This is less than would be normally expected with a system that incorporates both sensible and latent heat waste heat recovery (calculations/expectations would suggest >75 percent overall thermal efficiency based upon HHV). The overall values provided suggest only sensible waste heat recovery in practice. The timeline for the incorporation of the latent heat recovery is not known but data provided indicates a marked increase in thermal recovery in the first quarter of 2009. However, soon after the increased thermal recovery was noted, issues with the measurement of the energy recovery were noted (questionable accuracy of the values leading to unrealistic efficiency calculations). The latent recovery could well have been implemented in early 2009 but quickly ran into the problems of corrosion noted above.

Based upon a name plate value of 1 MW and an effective average energy output for the period of monitoring of approximately 750 kW-hr and compared with the annual average energy need of 5100 kW-hr and a peak load of 12 MW, the fuel cell provides approximately 15 percent of the average energy requirements and 8.3 percent of the peak loads for the campus' electric energy needs.

Figure 5-13: CSUN Fuel Cell Installation - Typical Energy Profile from April – June 2008

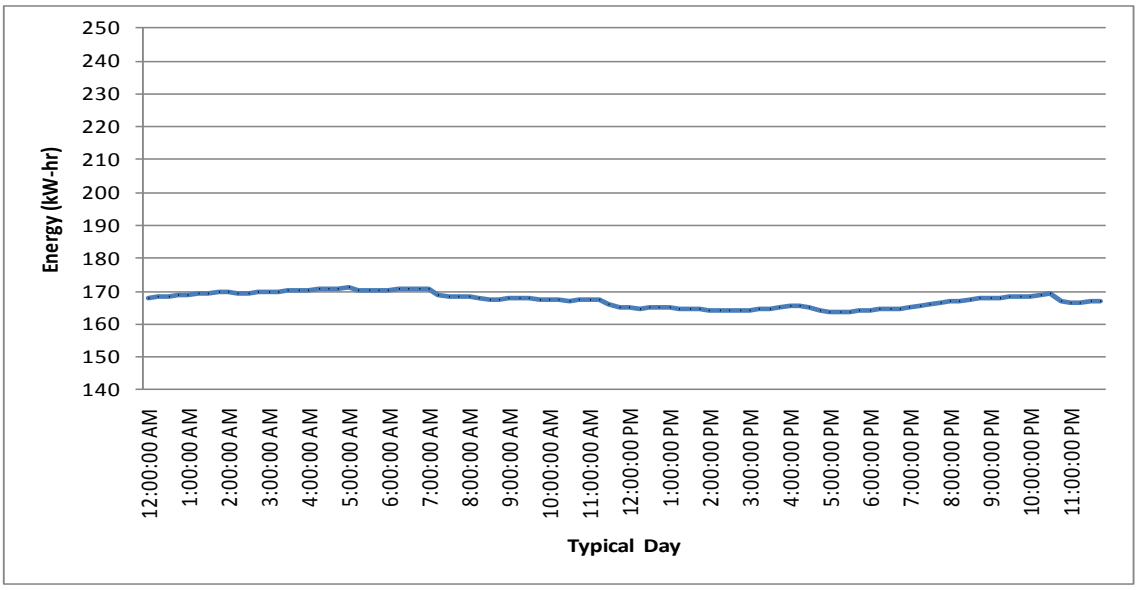


Figure 5-14: CSUN Fuel Cell Installation - Typical Fuel to Electric Power Efficiency (LHV) from April – June 2008

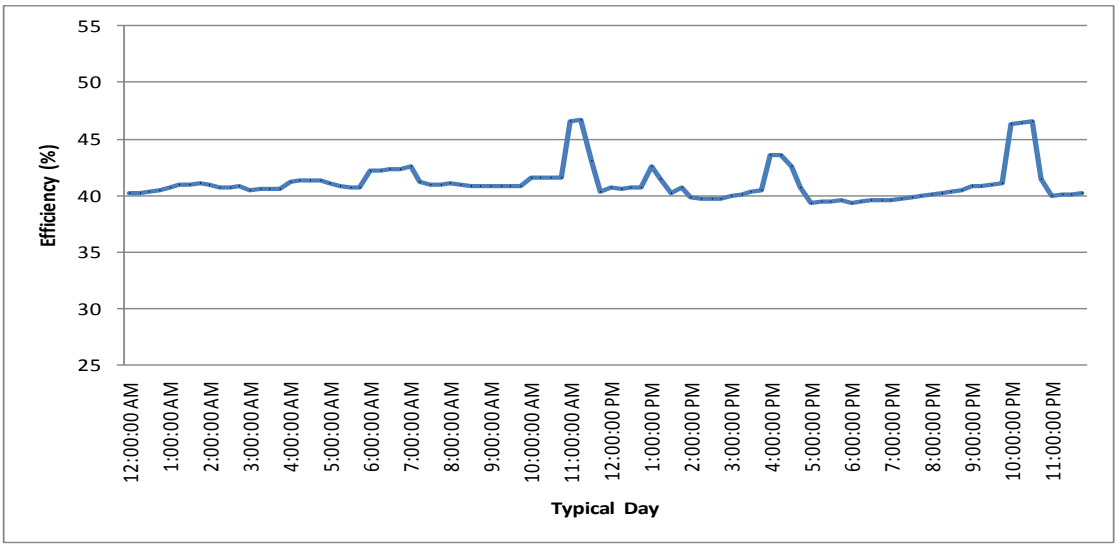


Figure 5-15: CSUN Fuel Cell Installation - Typical Overall Thermal Efficiency (HHV) from April – June 2008

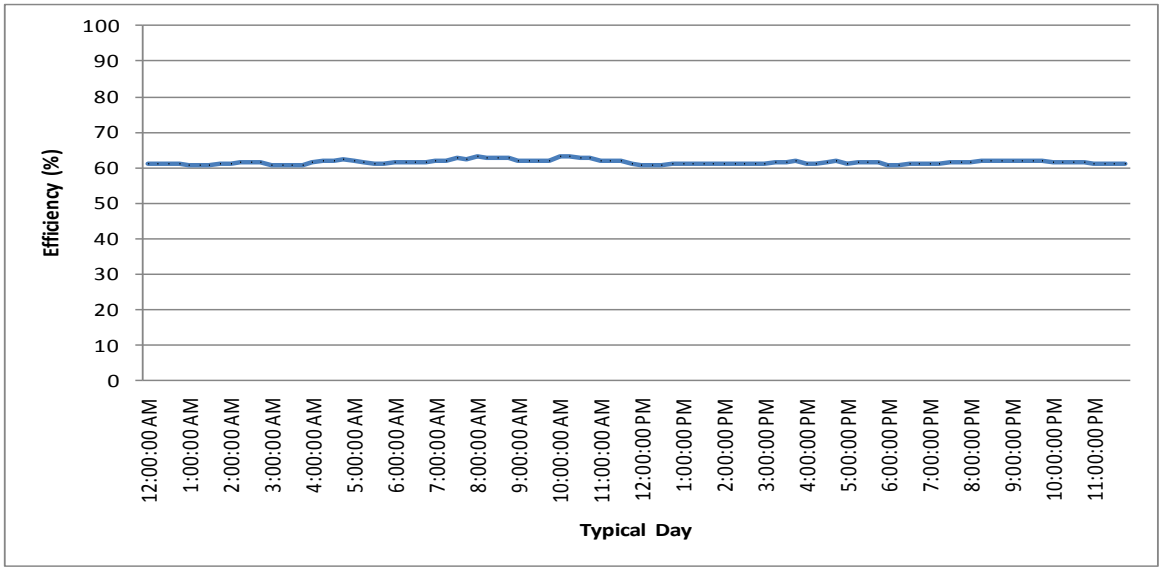


Figure 5-16: CSUN Fuel Cell Installation - Typical Energy Profile from July - Sept 2008

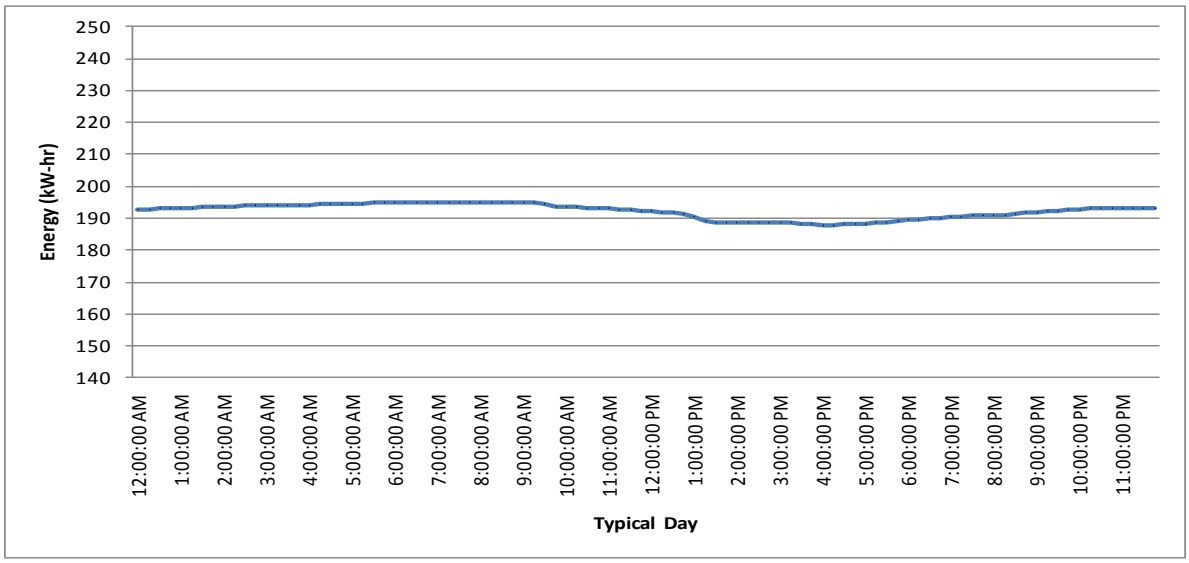


Figure 5-17: CSUN Fuel Cell Installation - Typical Fuel to Electric Power Efficiency (LHV) from April – June 2008

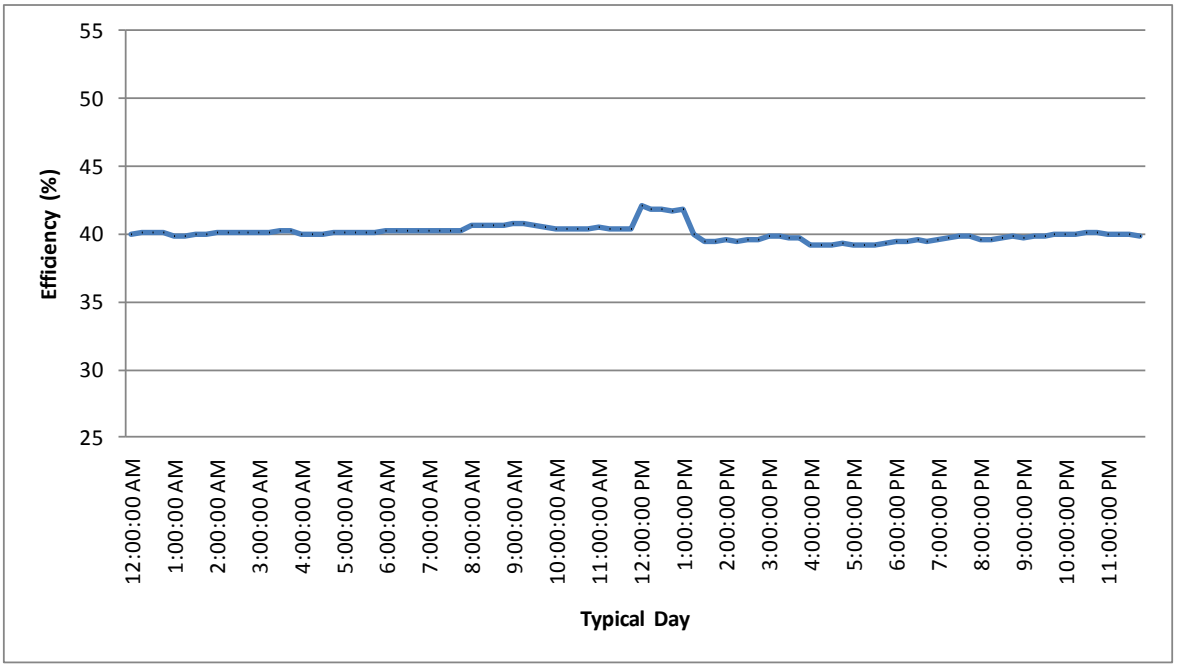


Figure 5-18: CSUN Fuel Cell Installation - Typical Overall Thermal Efficiency (HHV) from July - Sept 2008

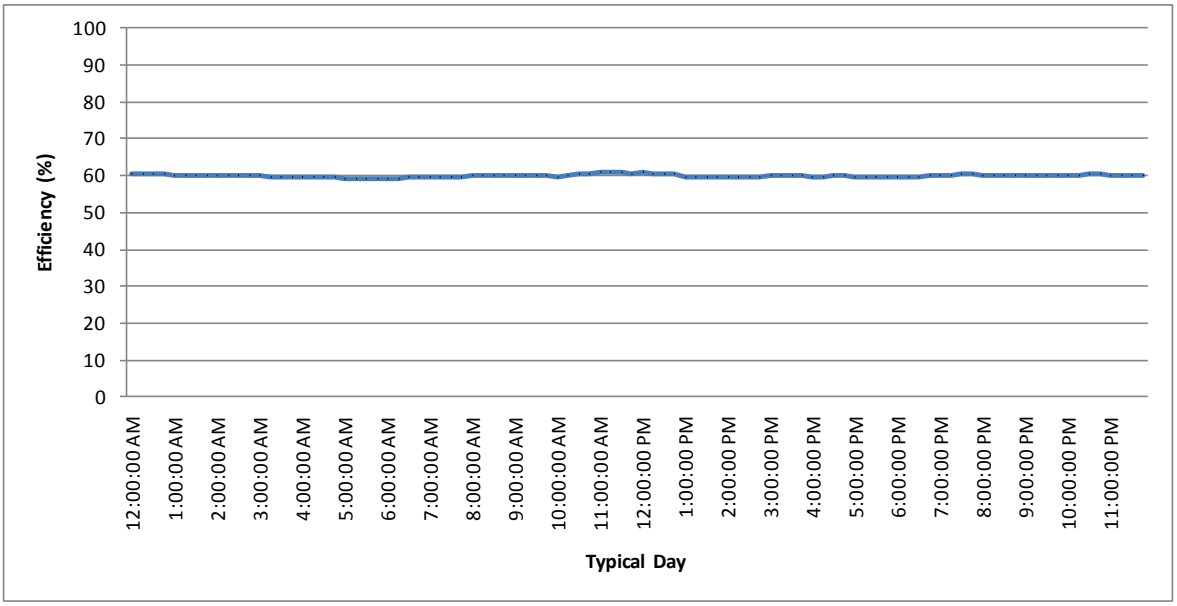


Figure 5-19: CSUN Fuel Cell Installation - Typical Energy Profile from Oct – Dec 2008

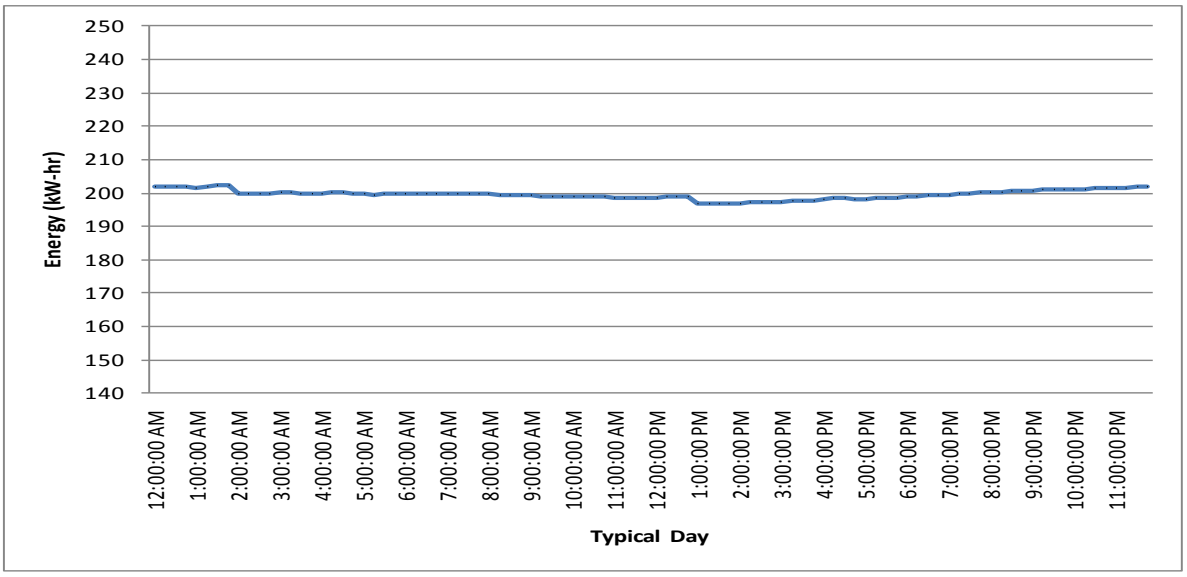


Figure 5-20: CSUN Fuel Cell Installation - Typical Fuel to Electric Power Efficiency (LHV) from Oct – Dec 2008

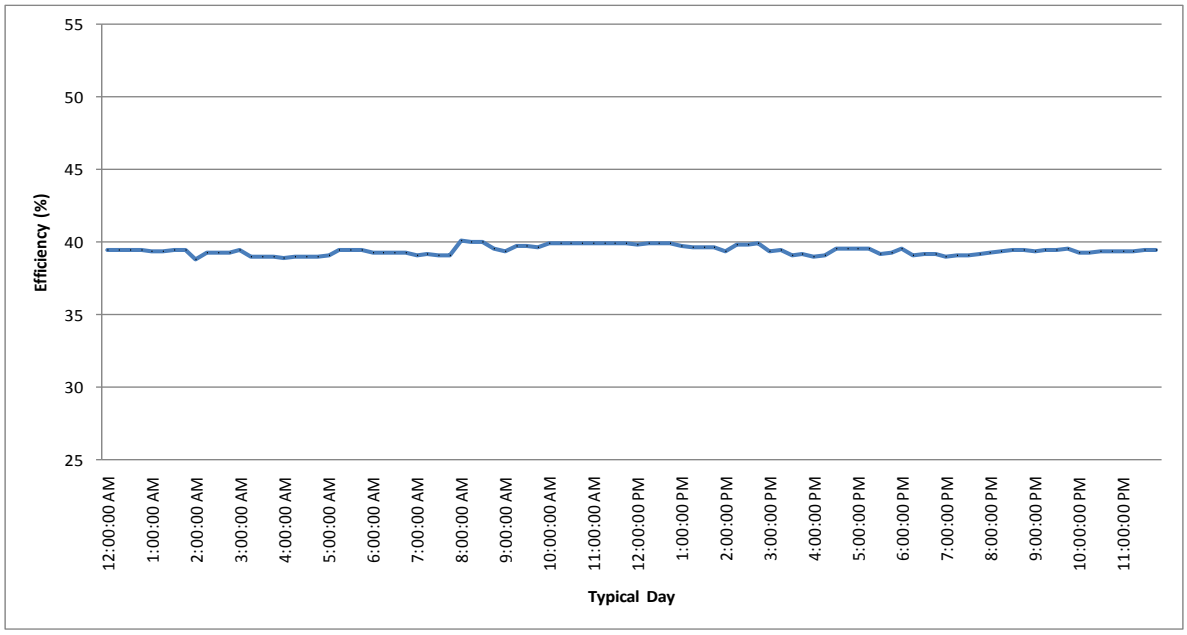


Figure 5-21: CSUN Fuel Cell Installation - Typical Overall Thermal Efficiency (HHV) from Oct – Dec 2008

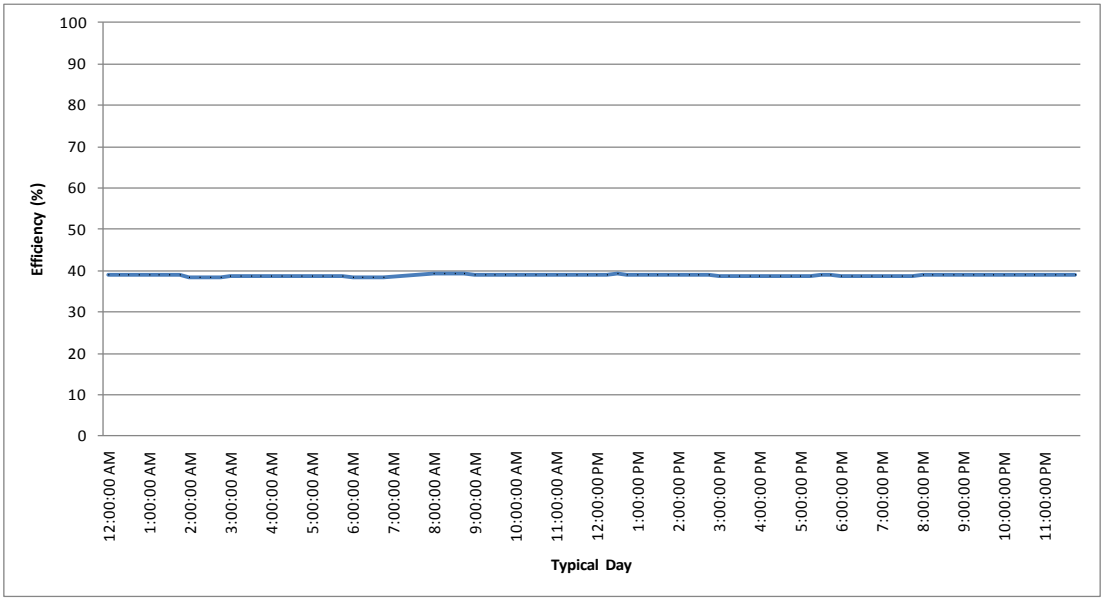


Figure 5-22: CSUN Fuel Cell Installation - Typical Energy Profile from Jan – March 2009

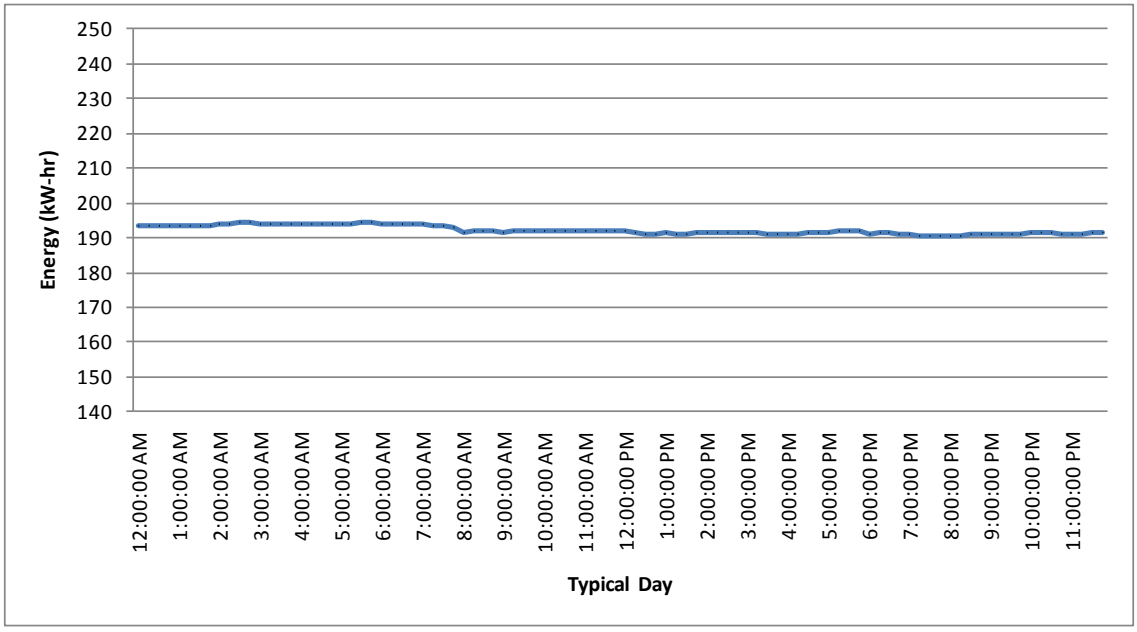


Figure 5-23: CSUN Fuel Cell Installation - Typical Fuel to Electric Power Efficiency (LHV) from Jan – March 2009

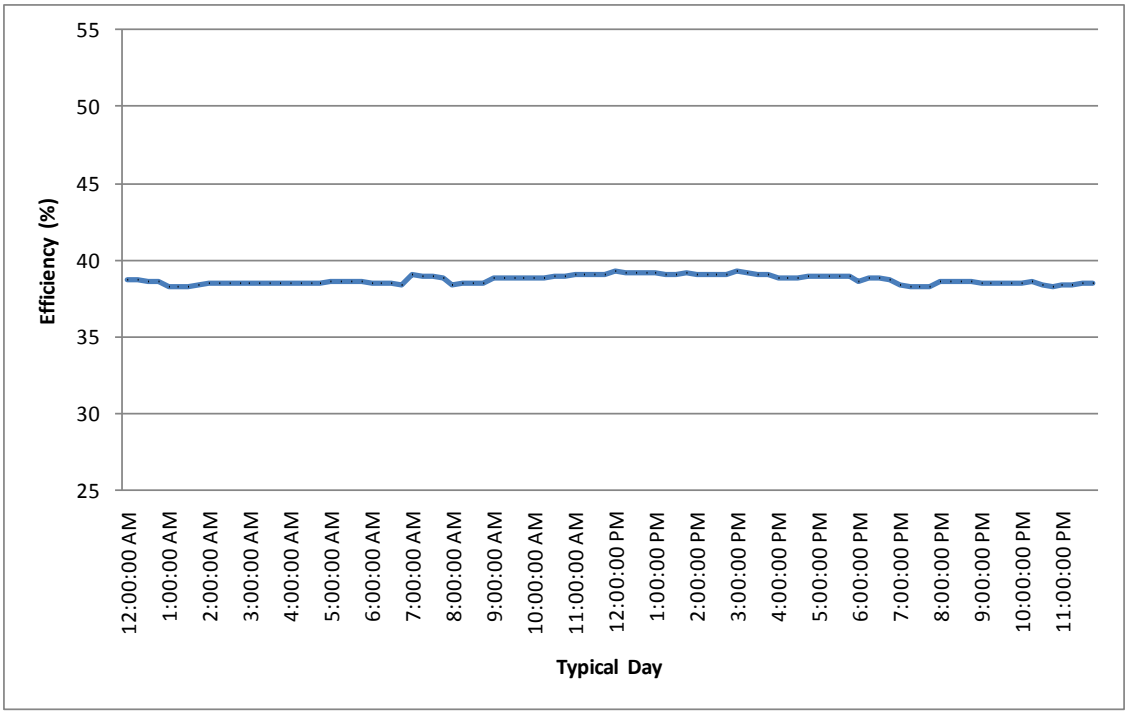


Figure 5-24: CSUN Fuel Cell Installation - Typical Energy Profile from April – June 2009

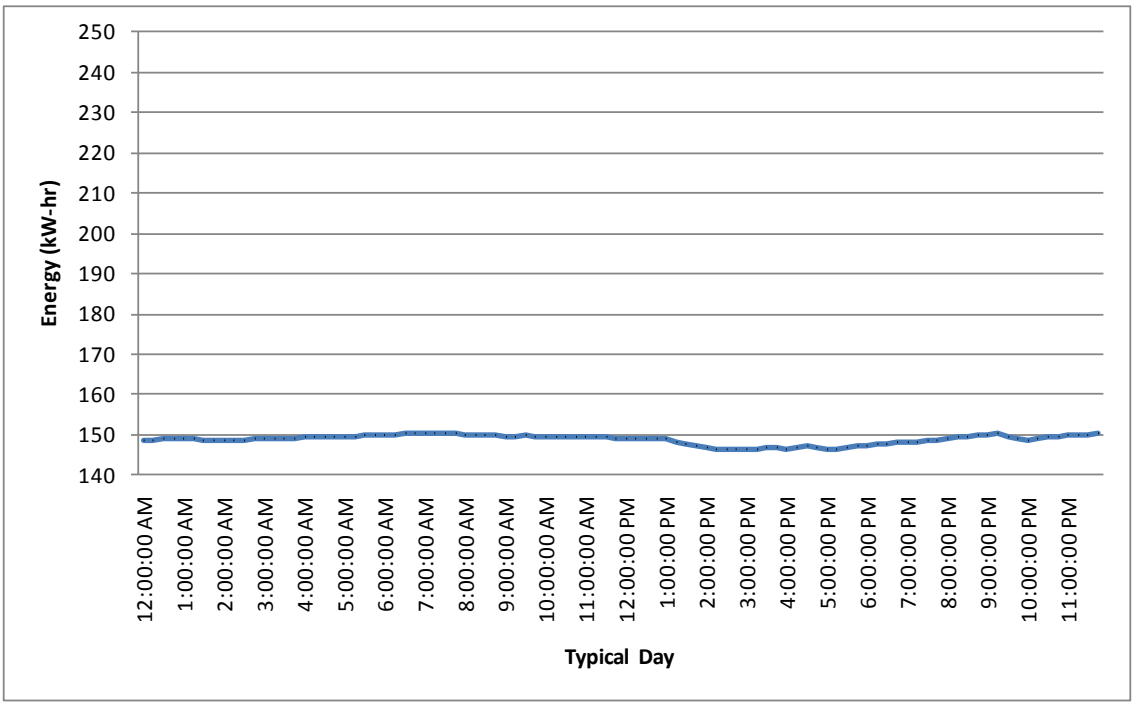


Figure 5-25: CSUN Fuel Cell Installation - Typical Fuel to Electric Power Efficiency (LHV) from April – June 2009

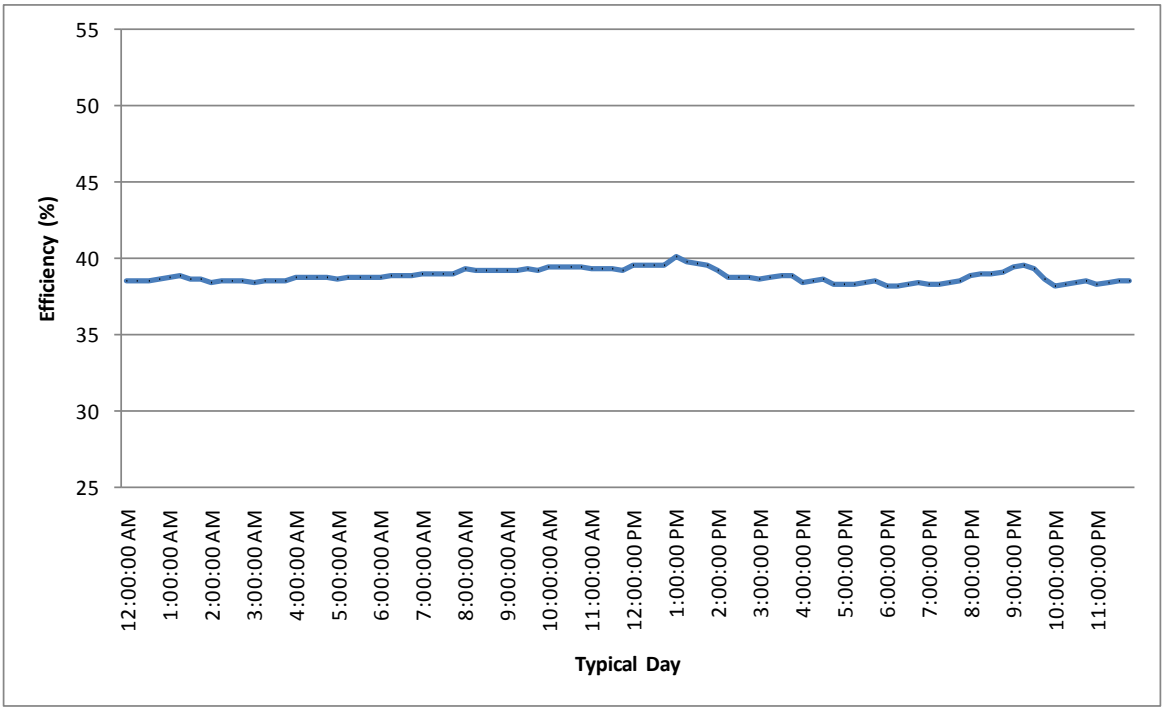


Figure 5-26: CSUN Fuel Cell Installation - Typical Energy Profile from July – Sept 2009

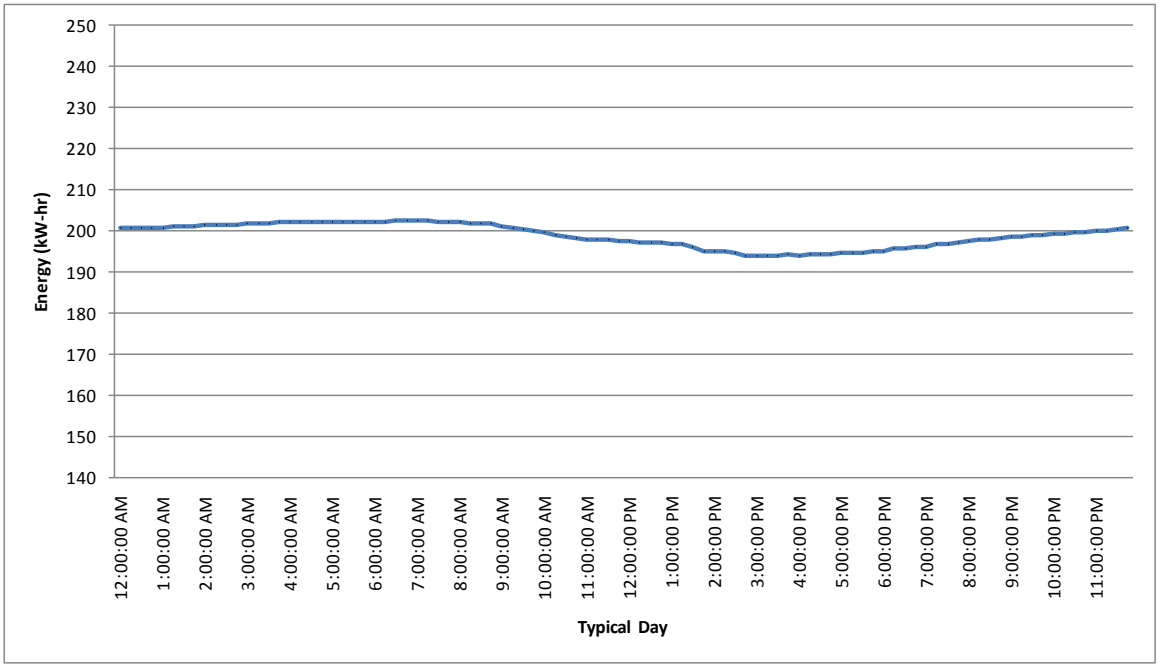


Figure 5-27: CSUN Fuel Cell Installation - Typical Fuel to Electric Power Efficiency (LHV) from July – Sept 2009

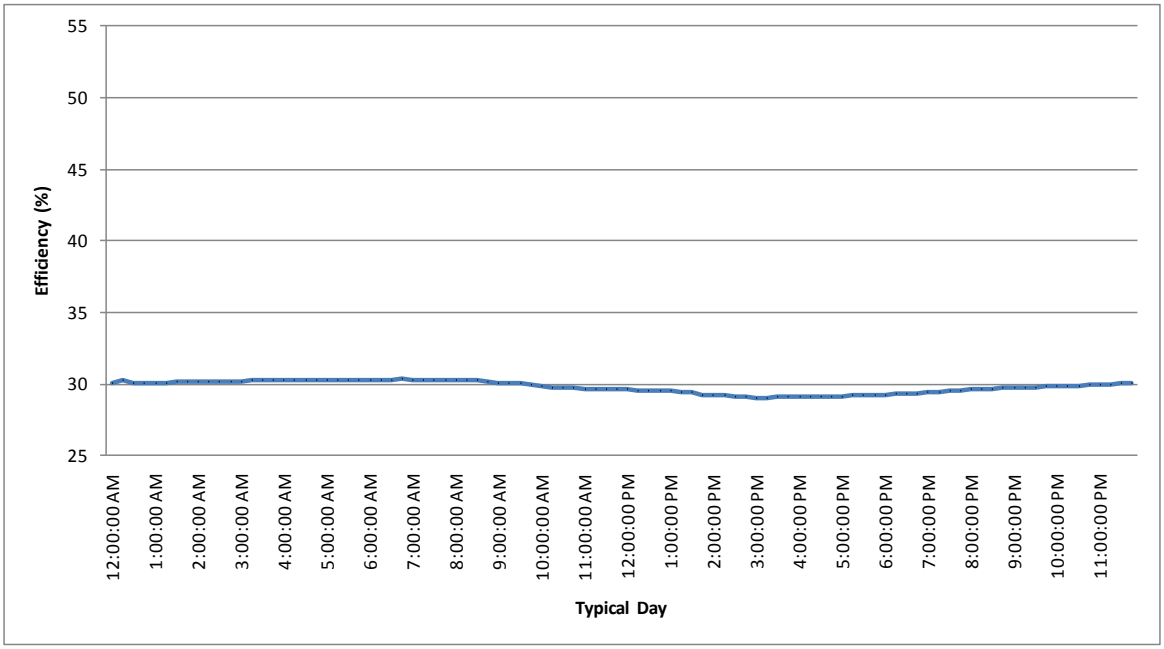


Figure 5-28: CSUN Fuel Cell Installation - Typical Energy Profile from Oct – Dec 2009

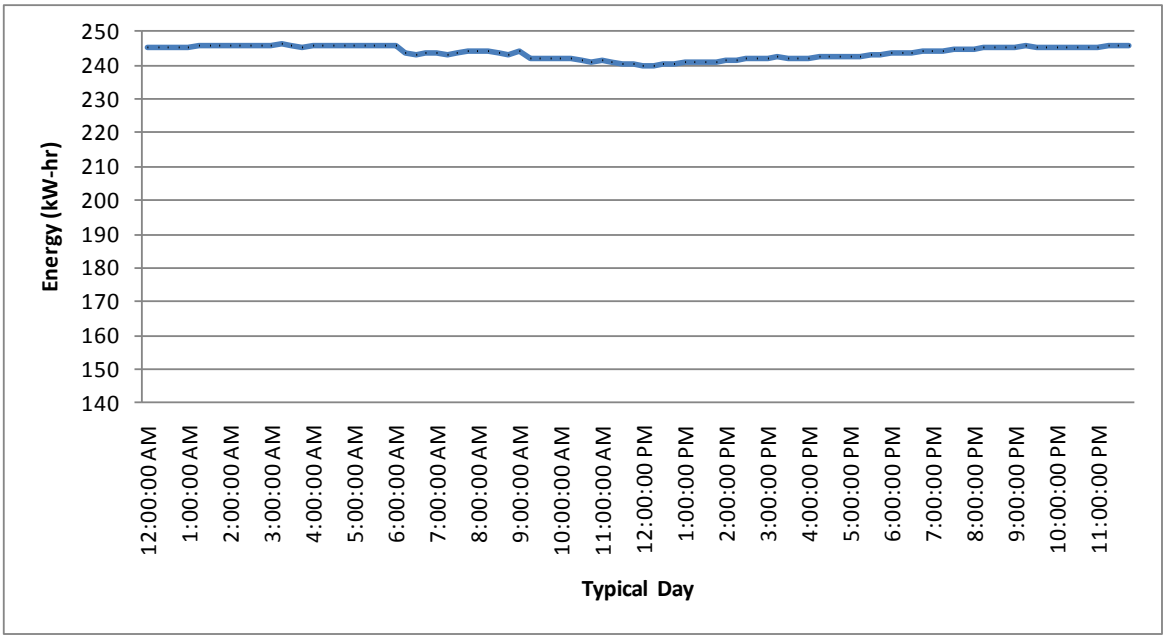
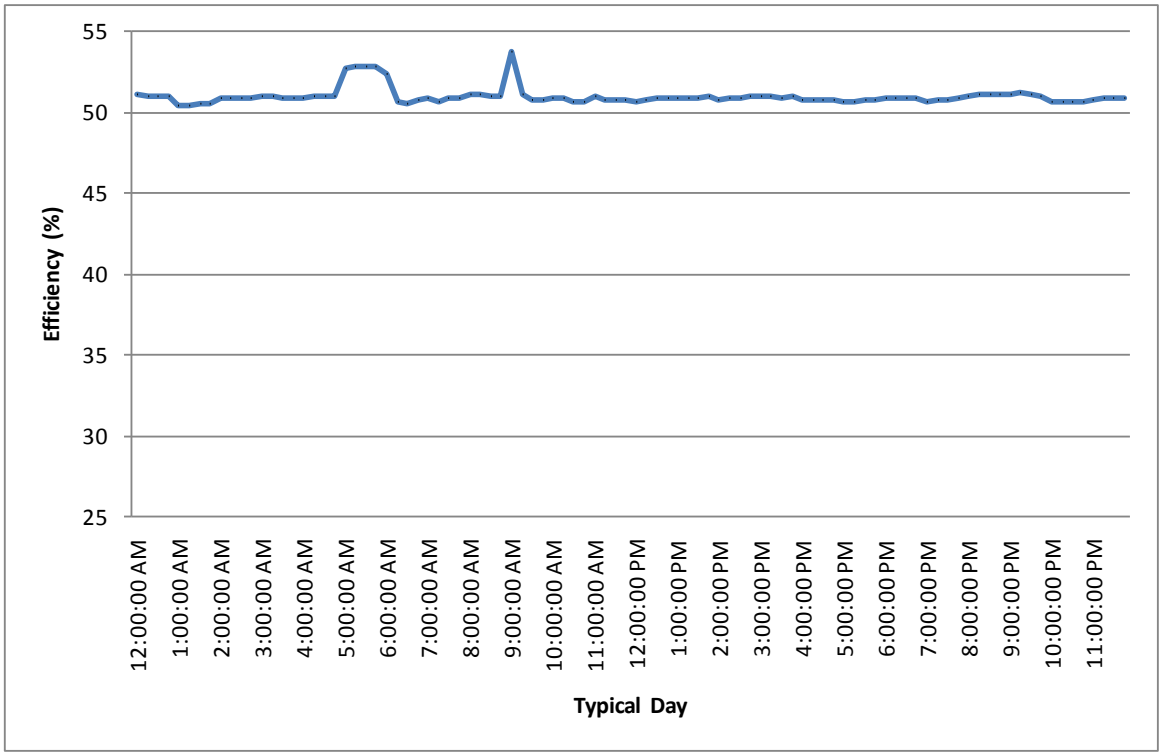


Figure 5-29: CSUN Fuel Cell Installation - Typical Fuel to Electric Power Efficiency (LHV) from Oct – Dec 2009



5.8 Pasadena City College (PCC)

Much like CSUN, PCC has been an aggressive and early adopter of CHP technology. An old campus, the facility has undergone a wide spread modernization and growth campaign from about 2000 and still in process today. In 2002/2003, the campus acquired and installed two 30 kW Capstone microturbines with a waste heat recovery system. This system was (and still is) used exclusively to heat an athletic pool for the campus. The desired energy is the heat for the pool with the electric energy as a beneficial by-product. The system is only utilized and coordinated with the pool need schedule and as such, its operation is seasonal and sporadic.

PCC has also installed an array of four 60 kW Capstone microturbines and a direct exhaust fired absorption chiller to support campus chilled water needs supplementing the Central Plant chiller system. The PCC installation is interesting in that one of the four turbines is capable of providing back-up power/emergency power for critical systems in the event of a power outage. This is the system monitored as part of the campus system.

The PCC installation performance is presented in Figures 5-30 through 5-39. This installation directly utilizes the exhaust stream from the microturbines to drive an absorption chiller. There is no gas to water heat exchanger to create hot water that is then used to "fire" an absorption chiller. As such, the effective use of the waste heat is limited to times when there is a cooling need for the PCC campus loop. Also note that the chiller operation is scheduled as secondary to

the operation of the PCC campus' central plant chillers. Whereas the electric load is utilized 24/7 for the campus, the chiller operation is much more sporadic and generally limited to the hotter months. Additionally, the four microturbines installed at PCC are quite old and have high operating hours logged (> 7 years old and 25,000 hours average for the four units respectively). As such, the low efficiencies measured, while disappointing may not be unexpected.

Figure 5-30: PCC MTG / Chiller Array - Typical Electric Energy Output from Sept-Dec 2008

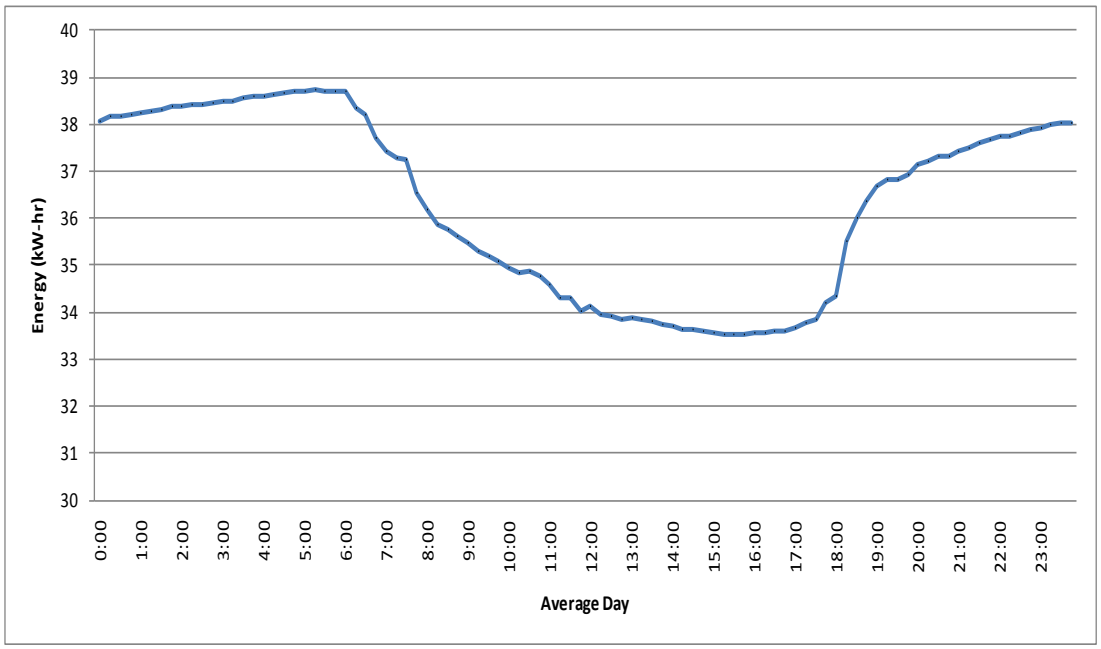


Figure 5-31: PCC MTG / Chiller Array - Typical Overall System Efficiency (HHV) from Sept – Dec 2008

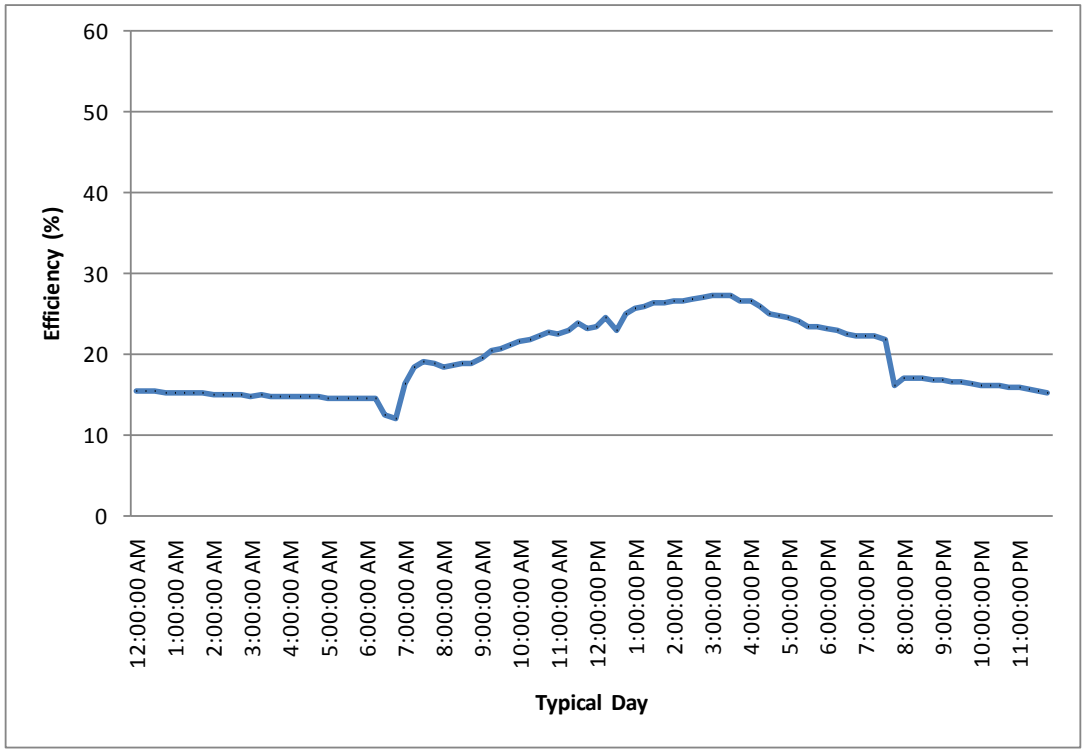


Figure 5-32: PCC MTG / Chiller Array - Typical Electric Energy Output from Jan – Mar 2009

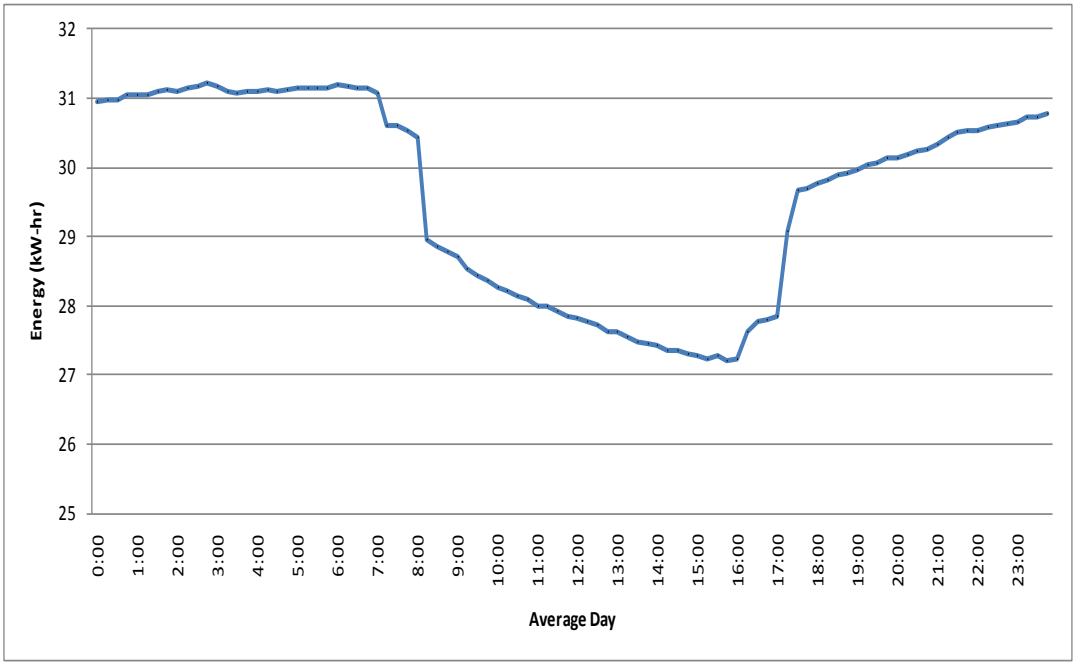


Figure 5-33: PCC MTG / Chiller Array - Typical Overall System Efficiency (HHV) from Jan-Mar 2009

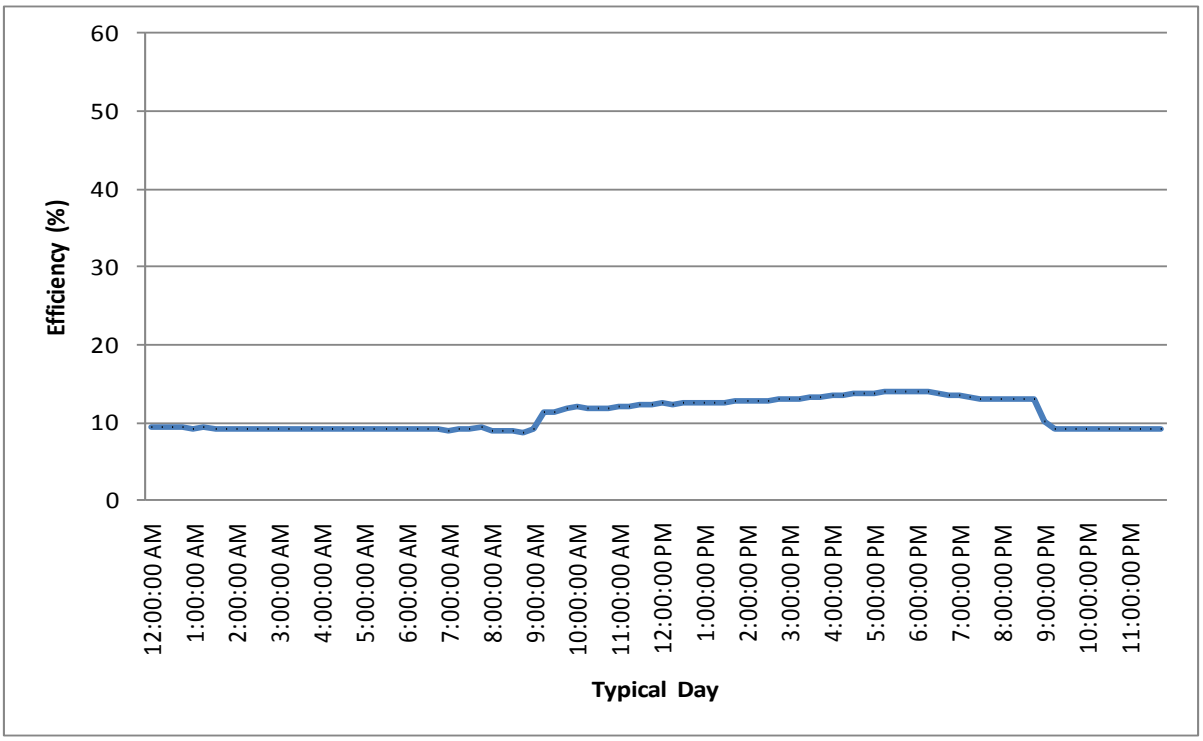


Figure 5-34: PCC MTG / Chiller Array - Typical Electric Energy Output from Apr-Jun 2009

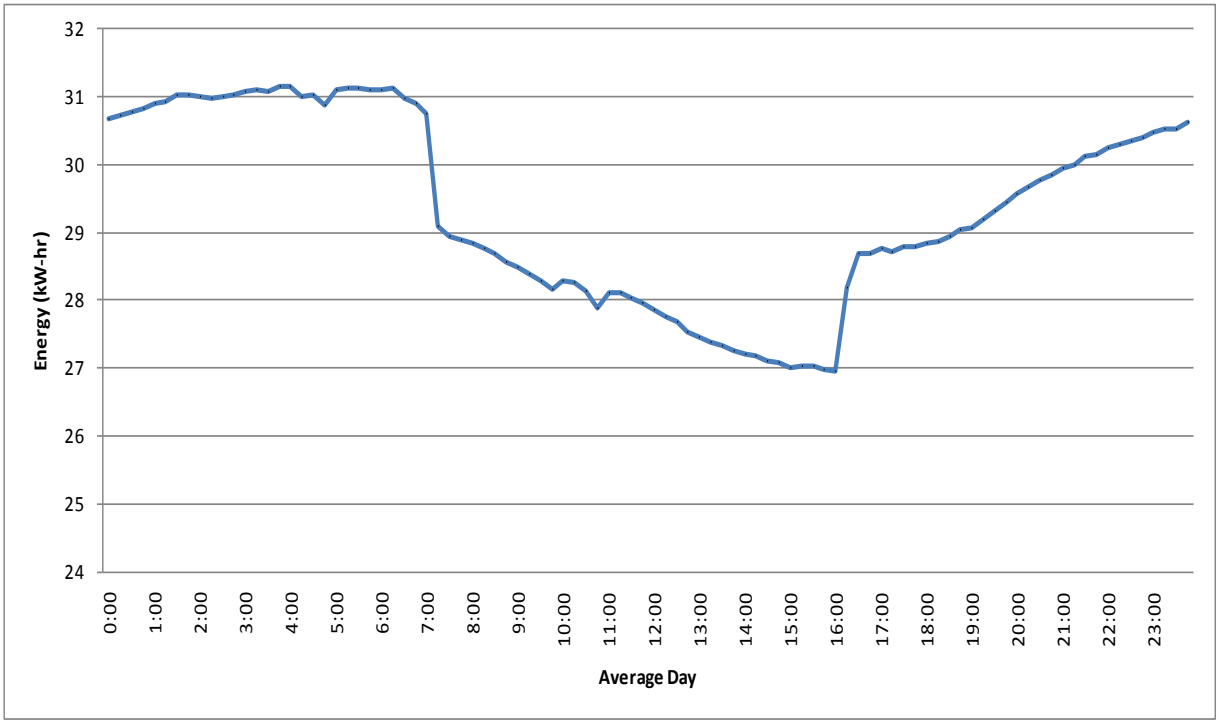


Figure 5-35: PCC MTG / Chiller Array - Typical Overall System Efficiency (HHV) from Apr-Jun 2009

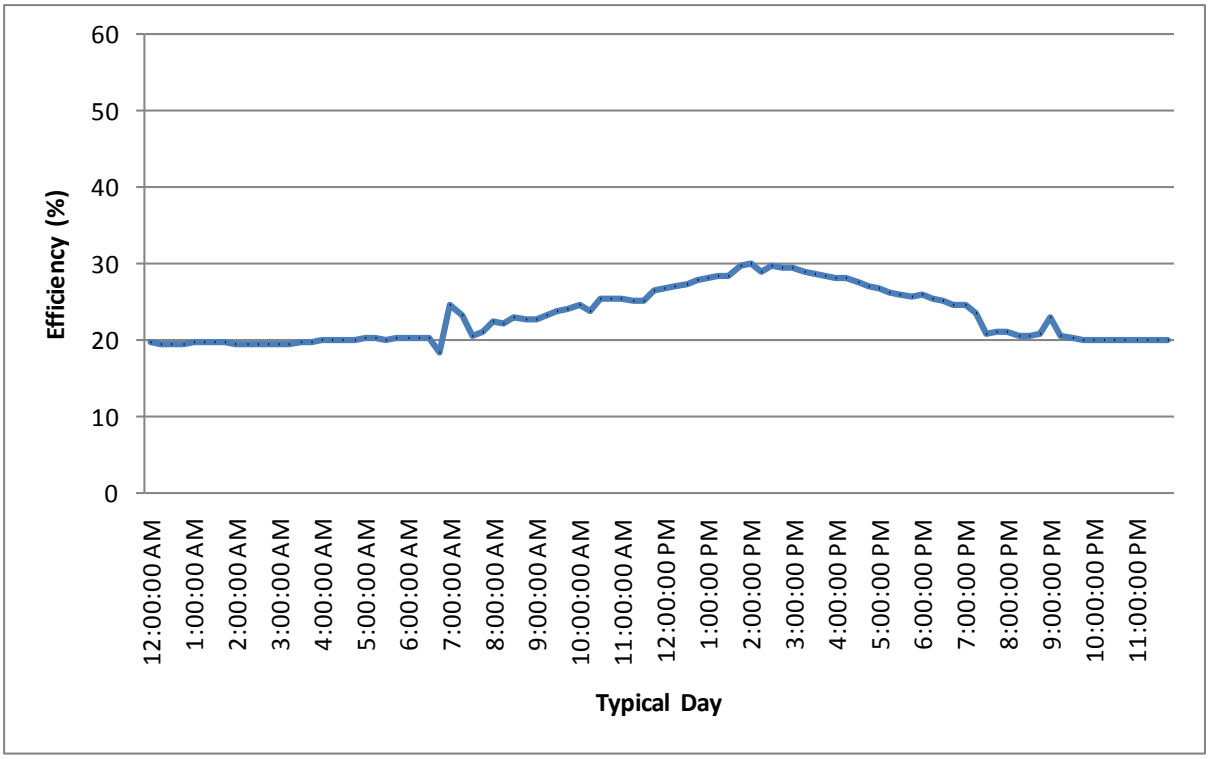


Figure 5-36: PCC MTG / Chiller Array - Typical Electric Energy Output from Jul-Sept 2009

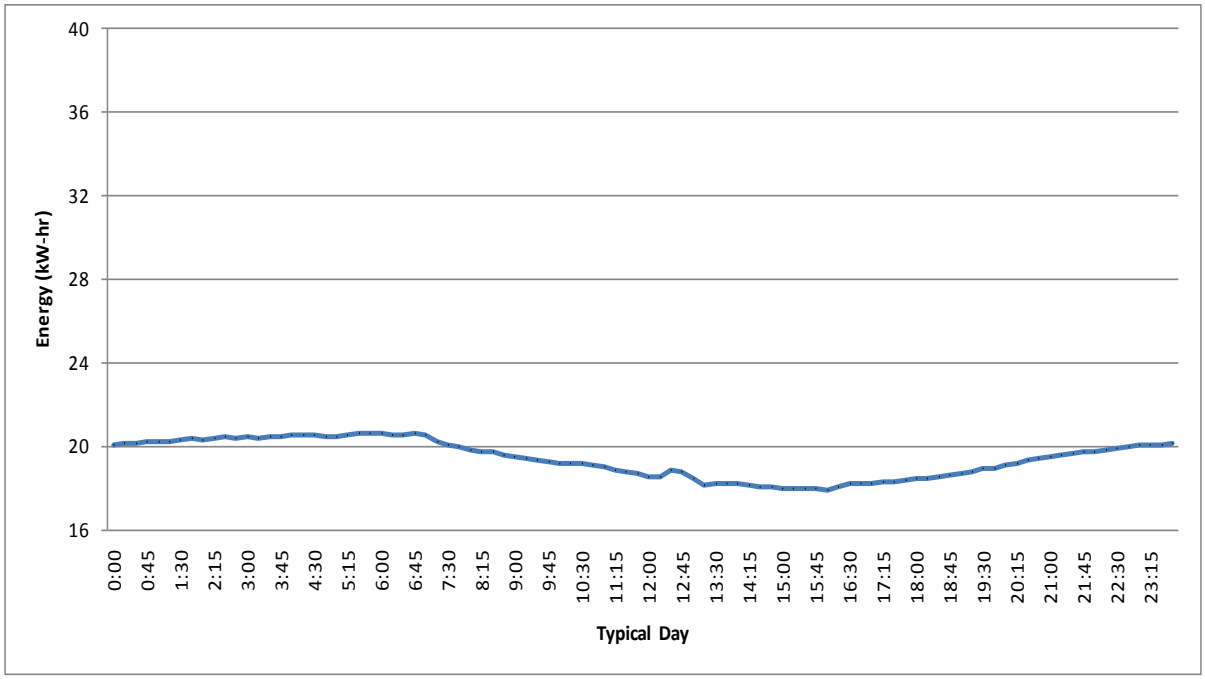


Figure 5-37: PCC MTG / Chiller Array - Typical Overall System Efficiency (HHV) from Jul-Sept 2009

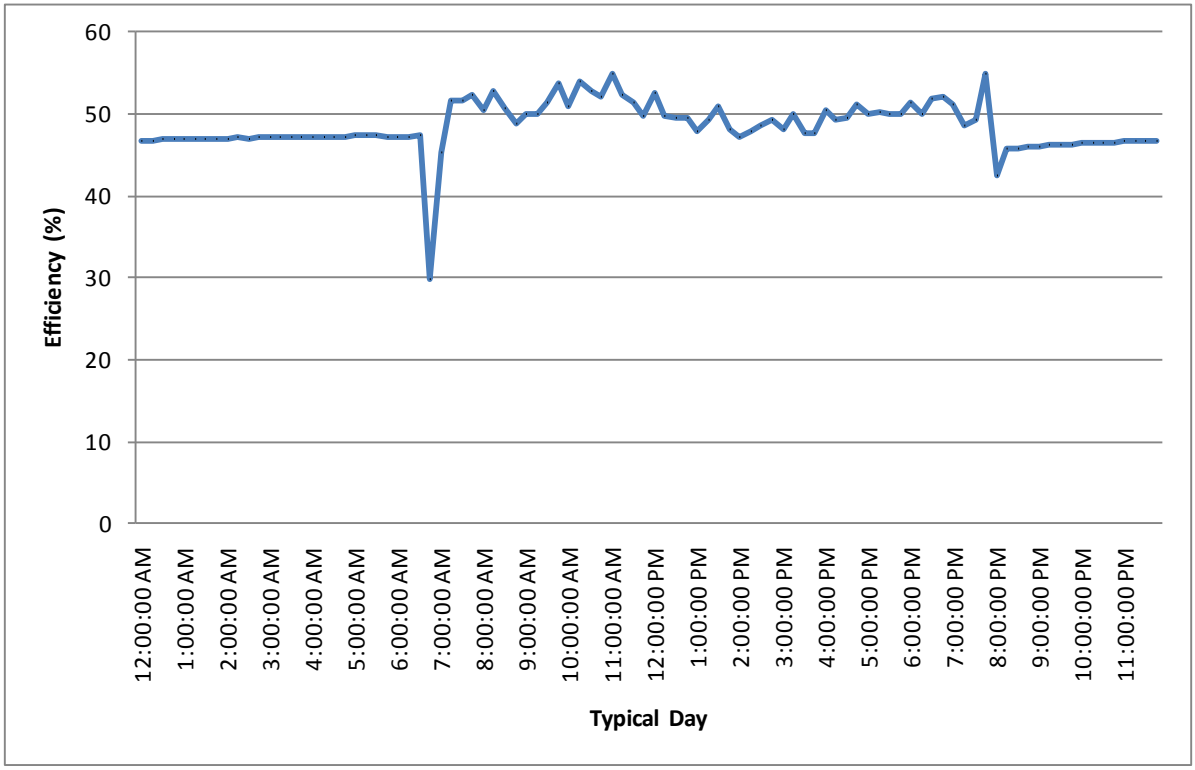


Figure 5-38: PCC MTG / Chiller Array - Typical Electric Energy Output from: Oct-Nov 2009

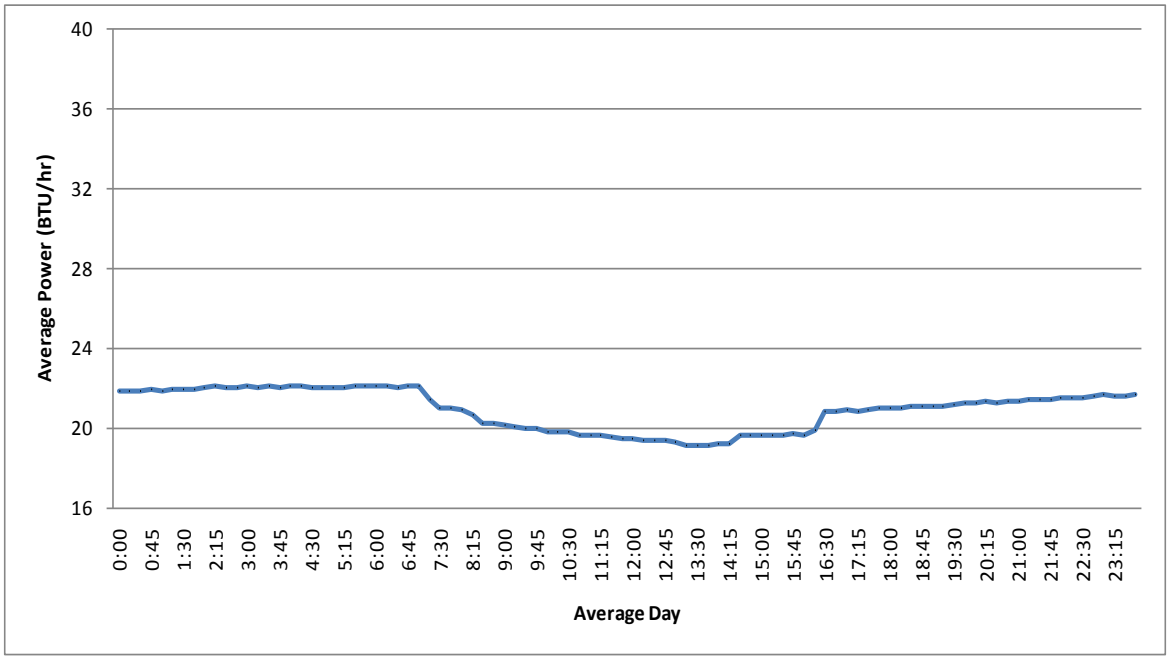
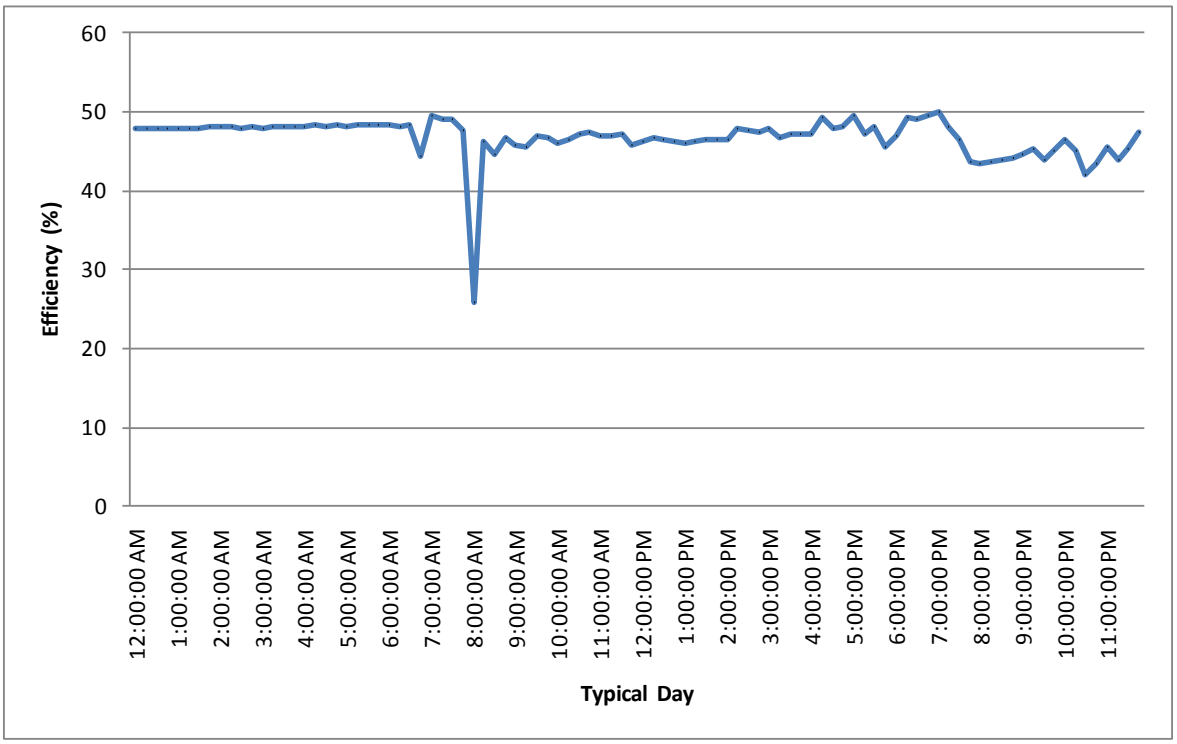


Figure 5-39: PCC MTG / Chiller Array - Typical Overall System Efficiency (HHV) from Oct-Nov 2009



5.9 University of California Davis Medical Center (UCDMC)

The UC Davis Medical Center is unique in this program relative to the application of distributed generation. Aside from the size of the system (26 MW gas turbine with waste heat recovery that has multiple potential uses), the facility relies exclusively upon the DG/CHP system to provide all of its electric, heating and cooling (including generation of steam) with the grid as backup. As such, the presented information in Figures 5-40 through 5-47 does not provide the energy production of the turbine or the system since this is nominally equivalent to and would be representative of the facility loads, not the capability of the DG system to meet the load. Rather, the figures present the fuel to electric efficiency of the gas turbine and the overall thermal efficiency. As with the other cases presented, the overall efficiency is presented in term of higher heating value of the fuel (1020 BTU/scf). For the fuel to electric efficiency, the results are presented in terms of the lower heating value of the fuel, consistent with the ASERTTI[35] distributed generation testing protocols.

For the 12-month period presented in Figures 5-40 through 5-47, the general trend is similar. That is, overnight electrical generation efficiency of approximately 28 percent due to the turbine operating at reduced load consistent with the facility demands at night Typically less than 10

[35] Association of State Energy Research and Technology Transfer Institutions; 455 Science Dr, Ste 200, Madison WI, 53711

MW as compared to the 26 MW rating of the turbine); overall thermal efficiency overnight is approximately 58 percent . As the loads come on line with the normal business hours, the turbine efficiency increases to between 31 percent and 32 percent , associated with the increased load demand moving more towards the full load; overall thermal efficiency increases to >60 percent and up to 64 percent . Throughout the year, the peak in efficiency for both the turbine and the overall facility seems to occur between 4 and 6 pm, ostensibly the time when the load for facility electric power and air conditioning would be at their peak.

What is not represented by these values is the flexibility of the waste heat recovery in meeting the other demands of the facility. Recall that the waste heat recovered in the heat recovery steam generator (HRSG) can be directed as needed to many applications, either operating alone or in combination: absorption chillers, hot water, and auxiliary electric power production. The overall thermal efficiency is based upon the waste heat recovered in the HRSG and not representative of the final use of the energy (i.e. the final "product").

In its role as the primary electric and thermal energy source for the Medical Center, the CHP system operated with a very high capacity factor. All of the outages during the monitoring period were scheduled representing normal preventative maintenance and as well as two periods dedicated to major but planned outages for service. Regular maintenance was generally scheduled for Tuesdays or Thursday on nominally two-month intervals. Outages were nominally 12 hours long from 5 am to approximately 5 pm for a total of 56 ½ hours for the period. Interestingly no attempt was made to shift the timing to "off-peak" hours but this may be a function of details of the agreement the facility has with the local utility (SMUD). The longer outages occurred in December 2008 (3-days) and March 2009 (4 days) for a total of 177 hours. These represent a total capacity factor of approximately 97.3 percent for the 12 months of monitoring; the regular service representing 0.65 percent of the full year and the extended service representing 2 percent of the full year.

Figure 5-40: UC Overall Electric Generation Efficiency from Oct - Dec 2008

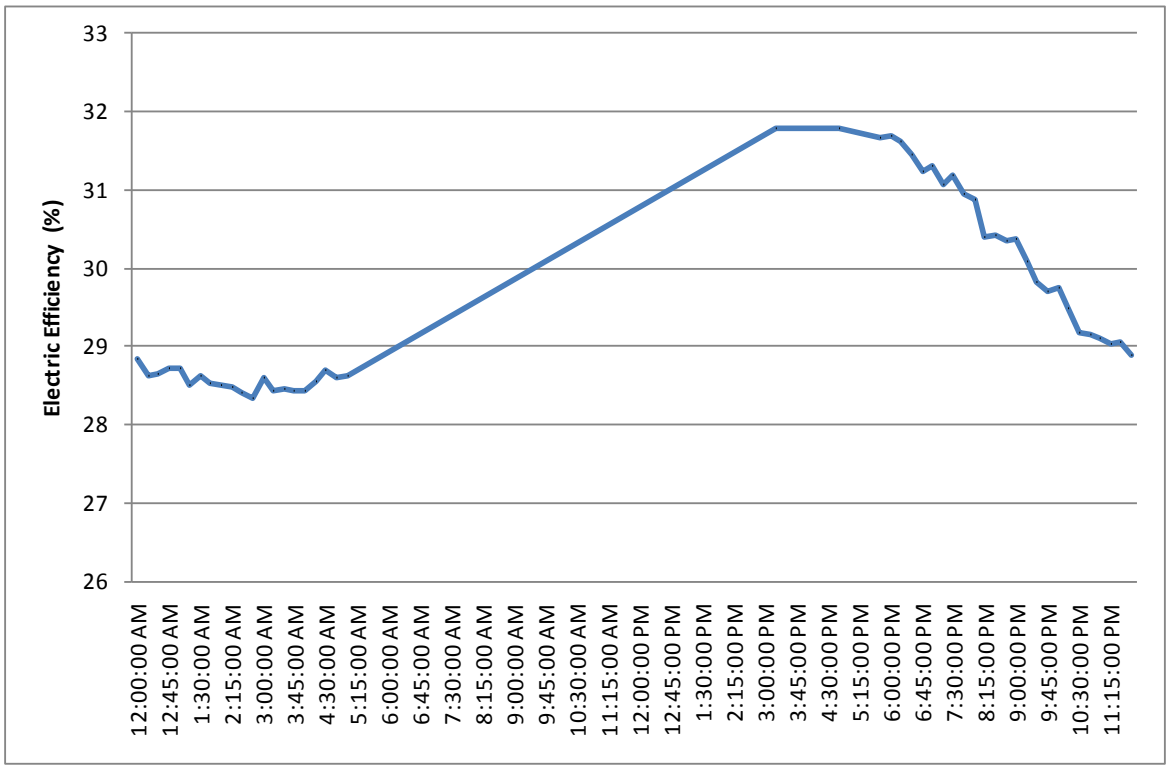


Figure 5-41: UCDMC Overall Thermal Efficiency from Oct -Dec 2008

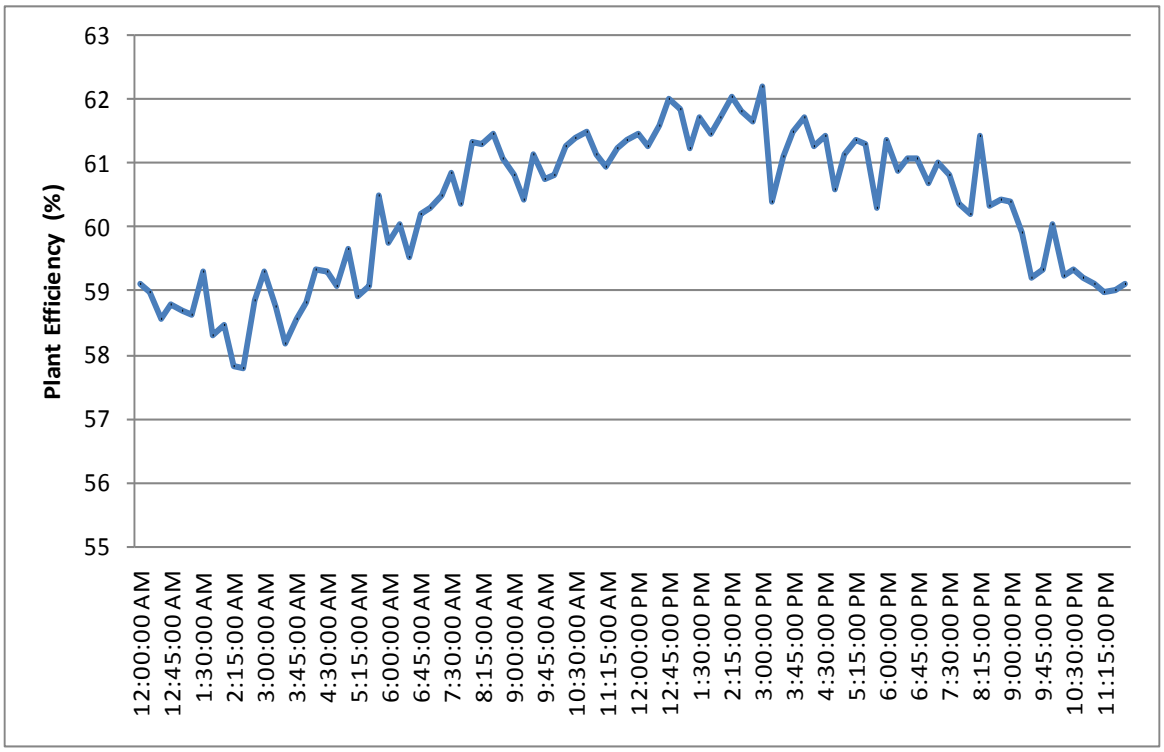


Figure 5-42: UCDMC Overall Electric Generation Efficiency from Jan - Mar 2009

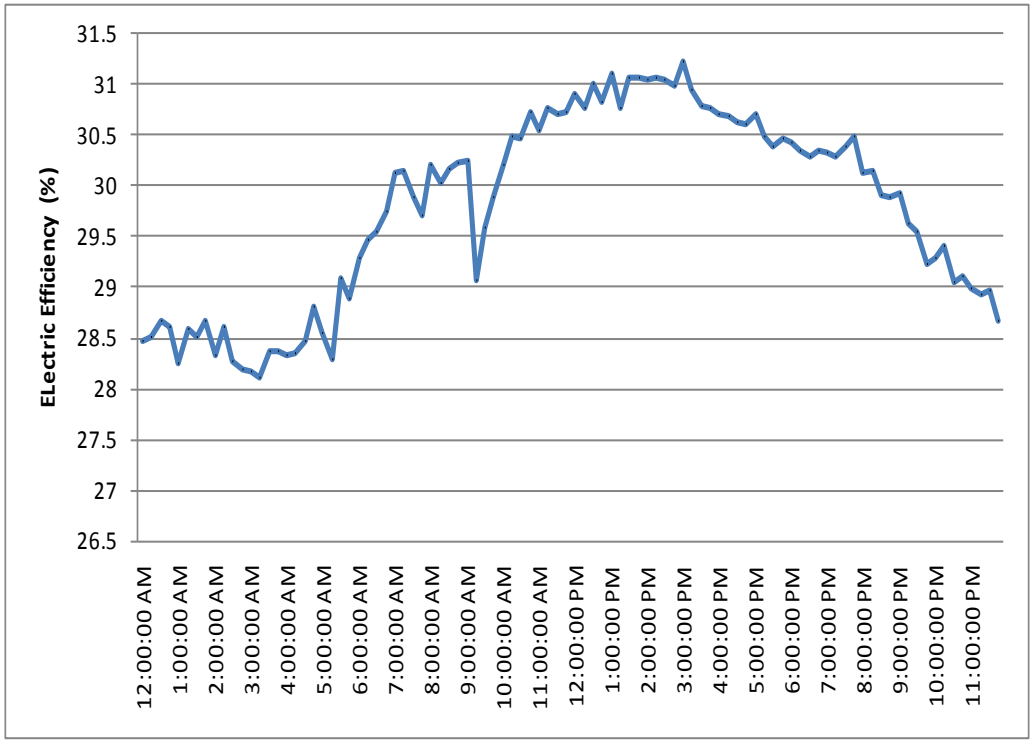


Figure 5-43: UCDMC Overall Thermal Efficiency from Jan - Mar 2009

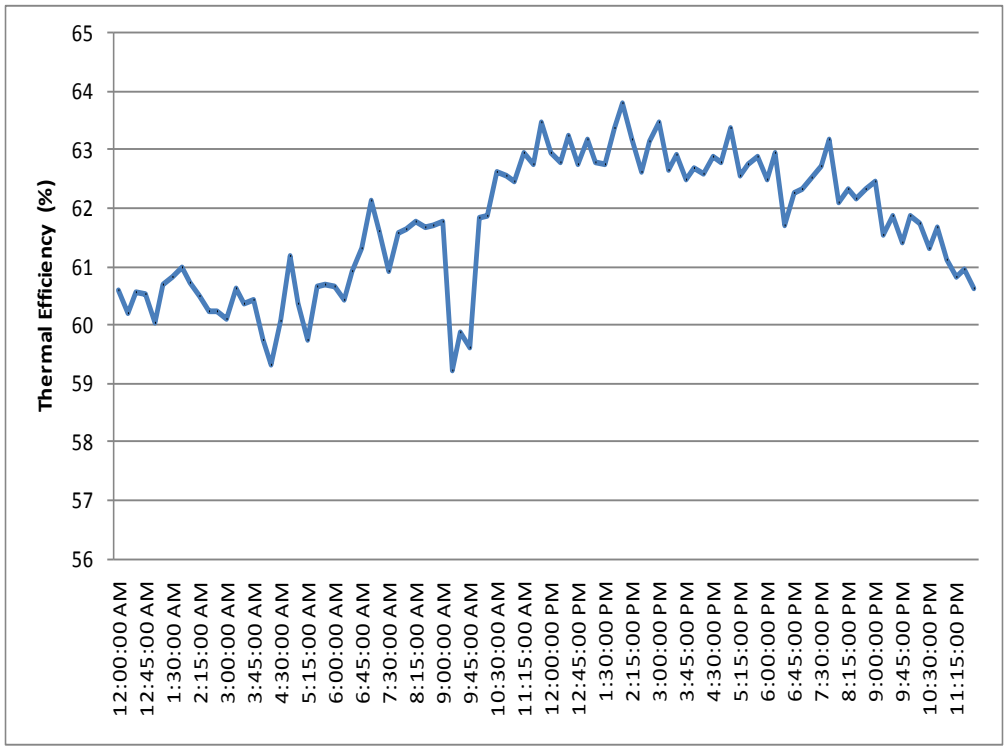


Figure 5-44: UCDMC Overall Electric Generation Efficiency from April - Jun 2009

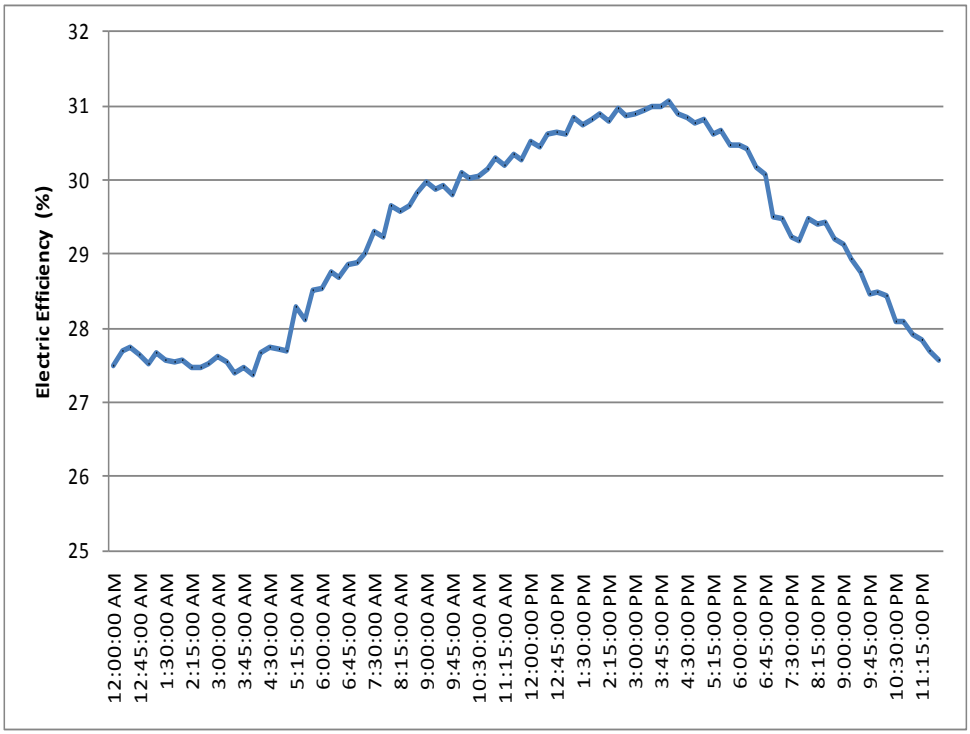


Figure 5-45: UCDMC Overall Thermal Efficiency from April - June 2009

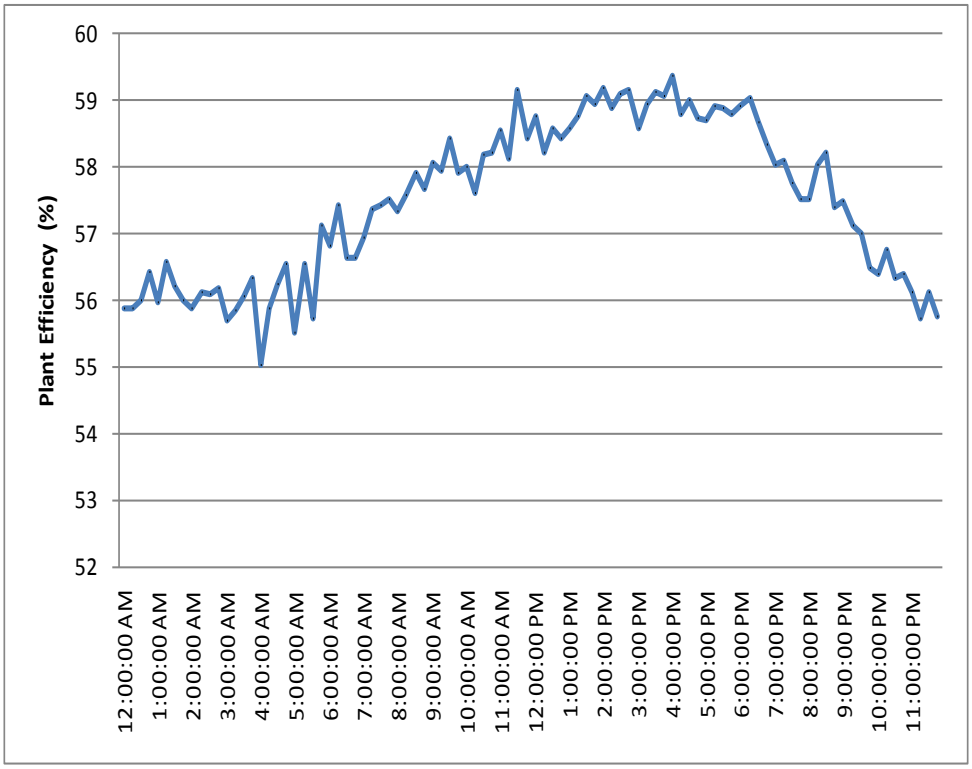


Figure 5-46: UCDMC Overall Electric Generation Efficiency from July - Sept 2009

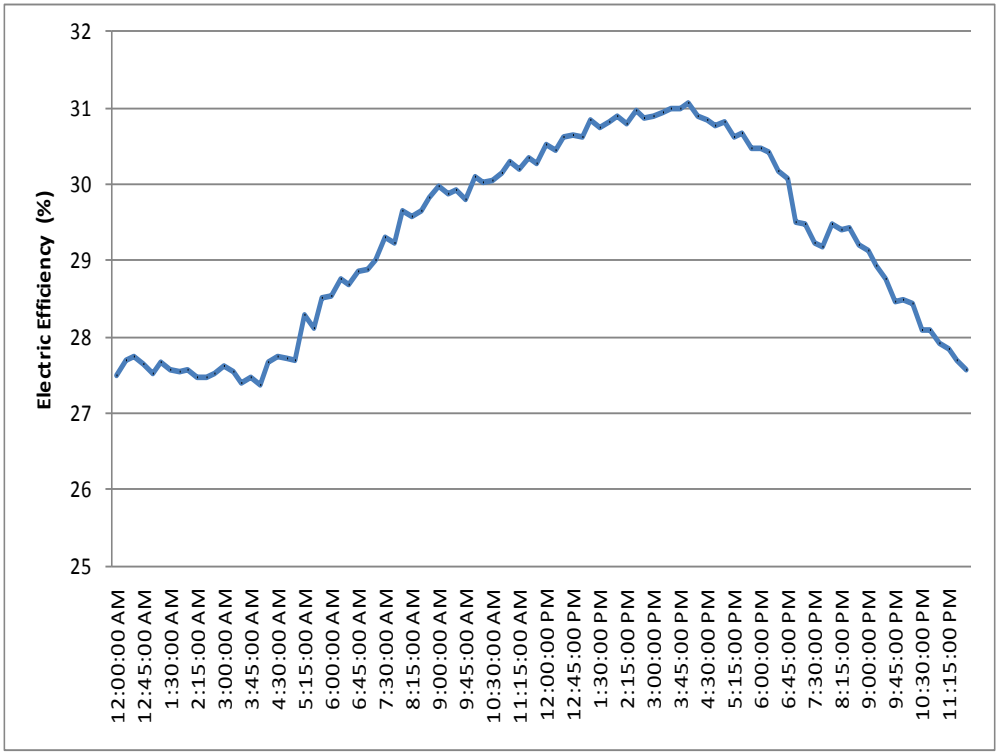
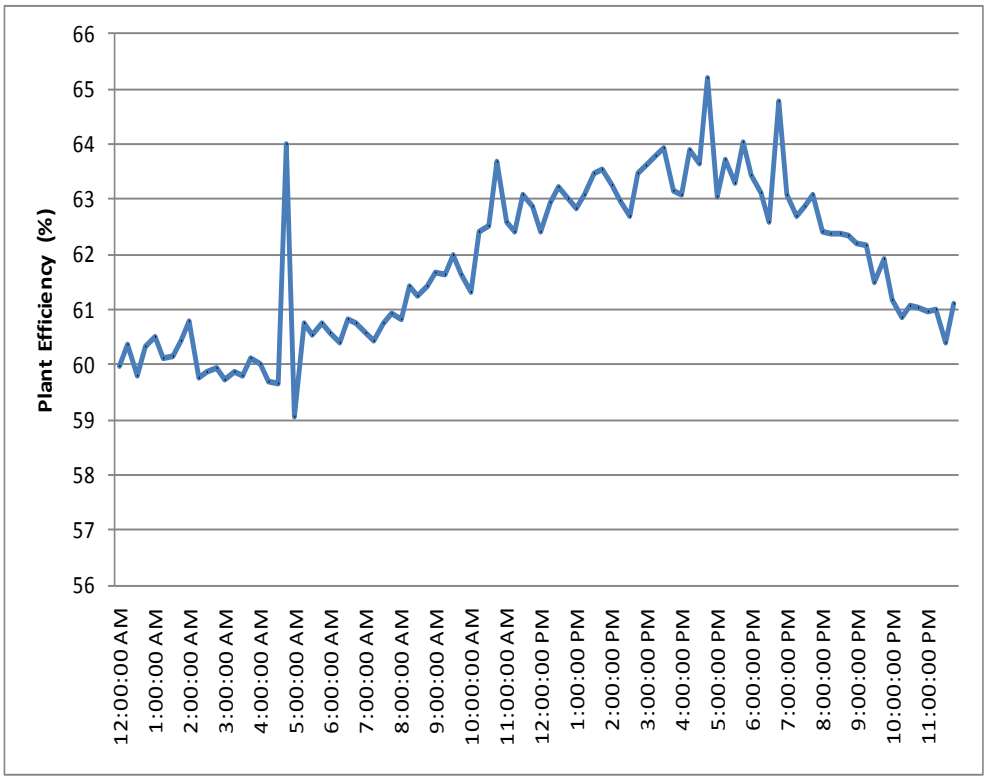


Figure 5-47: UCDMC Overall Thermal Efficiency from July - Sept 2009



5.10 Observations Regarding DG/CHP Utilization

The preceding examples, while small in number, could be considered representative of the general application and success of distributed generation. All are providing facility support in the form of both electric power and thermal support. All provide a snapshot of the level of success in the application of DG/CHP in facilities.

The facilities represent three of the six sectors investigated in this program: college/university, commercial office, and hospital. They also essentially represent three different distributed generation prime movers: microturbines, gas turbines, and fuel cells.

The Central Plant nature of the UC Davis Medical Center and the critical support it provides for the facility operation is evident in the exceptional availability of the system during the period of monitoring during this program. The system inherently warrants high levels of system support from the facilities group at the UCDMC, certainly a consideration during the system's initial design and deployment. The fuel to electric efficiency measured is consistent with the expectations of a gas turbine engine of the size and vintage installed. The overall efficiency is perhaps lower than what would be expected; however, note that the engine is greatly oversized for the facility (26 MW rating versus nominal hospital loads of 15-18 MW) with room for future expansion. The same argument can be made for the waste heat recovery in that the site loads are currently less than the capacity of the system. Hence, some waste heat must be bypassed leading to reduced overall thermal efficiency. However, this site does well represent the potential of DG/CHP for exceptional efficiencies when designed to meet the entire load profile for a site.

The history of the CSUN fuel cell installation as documented in the monitored data is one of continual refinement as well as the issues associated with trying to maximize the waste heat recovery. The improvement of energy output and overall efficiency are testament to the on-going efforts of the staff at CSUN. The data for the period of Oct – Dec 2009 are representative of the expected fuel cell operation owing to both continual system refinement as well as a likely stack replacement. Unfortunately, the waste heat recovery data is somewhat more erratic owing to system issues with the latent heat recovery from the exhaust. However for small segments of data that are deemed accurate, overall efficiencies of more than 85 percent have been measured. While large amounts of waste heat capture are possible with latent heat recovery, its application in general DG/CHP applications must be carefully weighed against the added maintenance necessary due to the corrosive environment and the quality of the heat recovered relative to the application.

PCC has an array of four older, high operational hours, C-60 turbines with direct waste heat recovery to an absorption chiller. While an admirable system that should have provided exceptional operational efficiency, the overall system efficiency suffered from both the age of the turbines and numerous operational problems with the chiller. Further, the age of the turbines complicates the continued service since Capstone does not support some of the key components of the system as is but requires upgrades.

SCAQMD, like PCC has an array of four older turbines that suffer from the same reductions in power output, efficiency, and serviceability as the PCC system. However, the waste heat recovery in the form of hot water to augment the on-site boilers does result in better overall efficiencies due to higher availability. The simplicity of the system certainly helps in this regard with a simple heat exchanger and pump as opposed to the complexity of an absorption chiller system with multiple possible points of failure. The second, three-turbine array at AQMD extends the same system design with upgrades to the heat exchangers that have been identified over the years. The age and improved waste heat recovery result in increased output and efficiencies than the older array. One system design of concern at both AQMD installations is the distance between the waste-heat capture points and the point of connection with the building-heating loop. The program did not measure the temperatures at the point of connection but rather at the heat exchangers. The energy loss and parasitic pumping loads associated with the waste heat recovery were not quantified but are suspected to be significant.

CHAPTER 6: Summary and Conclusions

6.1 Introduction

This project has reviewed the current market status for CHP in California, the current technical performance of various types of CHP equipment, and the overall policy environment for CHP in California. In addition, the effort reported here analyzed in detail the potential project and market-level impacts of the current design of the SGIP. Finally, the project compiled and analyzed building-level energy use data to identify the potential for further CHP development in key California market sectors that are believed to have further CHP technical and economic potential.

Based on the analysis conducted in this project and described in the previous chapters, the following sections review the key findings and conclusions of the study. Also offered are a few recommendations for how the SGIP might be slightly modified to attract a higher level of viable project applications, helping it to advance the development of CHP/WHP in California as intended by the California legislature when the program was last re-authorized.

6.2 Key Project Findings

Project key findings and outcomes are summarized below. In general, the market for CHP in California remains interesting and with potential, but with many nuances and complexities described in this paper and other recent reports[36]. The key findings from the study with regard to the specific subject areas examined are summarized below.

6.2.1 California's Installed CHP Base and Further Market Development

- Recent PCEAC efforts to promote exploration of CHP in key market sectors in California believed to have significant remaining potential, including the hospital/health care sector and the WWTP sector, showed significant interest and follow-up activities. These were related to CHP sector webinars held by the PCEAC in Spring/Summer 2013.
- California's CHP installation database currently lists over 1,200 CHP sites in California, but many of these are aging facilities with uncertain futures. Efforts by the PCEAC to assist ICF International to update the California database revealed many sites that are no longer in operation, that have either been removed from the database or put in an "idled" mode as appropriate.
- Recent policy developments such as "must take" rules for CHP enacted by CAISO suggest that the state recognizes the potential benefits of maintaining and expanding CHP in California.

[36] In particular as reported in Hedman et al. 2012; Neff, 2012; and Stadler et al. 2013.

6.2.2 Analysis of the Economic Impacts of SGIP

- Broad analysis of potential power market trends associated with potential imposition of some level of carbon pricing shows increasing additions of renewable and natural gas power and lower levels of coal power investment. It is unclear, however, how much of this natural-gas based generation might be distributed CHP compared with larger combined-cycle power plants.
- California market-level analysis of CHP implementation related to the availability of the SGIP program shows only a small impact of the program, assuming current natural gas and electricity prices in California markets. This analysis was conducted by LBNL with assistance from PCEAC, using the DER-CAM distributed energy resource adoption model.
- However, in the presence of a natural gas "price adder" associated with the implementation of California's cap and trade program (for 2015 and beyond), CHP economics relative to a conventional case baseline do improve and CHP investments that were "borderline" become clearly economically advantageous.
- Actual applications for SGIP funding for "Level 3 – Non Renewable" projects have been limited since the program rules were broadened in 2011 to re-admit combustion-based CHP, perhaps related to the reasons described in this study.

6.2.3 Building Energy Analysis

- UCI measured and CEUS data are reasonably close agreement. Southern California location and perhaps narrower focus (in the case of health and hospital sector) perhaps are reasons for deviation in energy values.
- There is a seasonal variation in energy intensity but perhaps as a result of Southern California Centric locations, not too wide a variation.
- Temporal variations in measured energy intensity is critical for understanding energy needs for any sector that is not captured with an "average" intensity.
- Based strictly upon heat energy versus electric energy intensities, DG/CHP would seemingly be fuel cell and reciprocating engine centric. However, a significant shift in the heat to electric ratio would occur if the available waste heat were utilized for thermal activated cooling (e.g. absorption chilling); the displaced chiller electric load and the increase in thermal need would shift the heat to electric ratio towards gas turbine systems (as is the case for the UC Davis Medical Center).
- Modeling of facilities for energy needs with minimal information (e.g. utilizing eQuest Wizard) can be very misleading. Models can be refined with some additional building specifics to better match. However, a good understanding/assessment of building needs and energy profiles is vital as models tend to underestimate loads and cannot capture the specifics of a particular facility without this information.

- Application/sizing of CHP systems to date, with some notable exceptions, has been one perhaps best described as a supplement "peak shaving" system to existing building services and needs. Very few facilities have developed/implemented systems that meet all of their needs, both electrically and thermally. When used in the supplementary role, the non-critical nature of the systems tends to result in reduced operation and more importantly reduced attention/service/maintenance (i.e. easy to forget that inevitably results in reduced efficiency and impact on the facility. Conversely, where a facility has interest in the system, especially when they CHP system provides the majority (or all) of the facilities electric and thermal needs, there is a strong commitment on the part of the facility to maintain and service the CHP equipment to insure strong and reliable performance.

6.3 Policy Recommendations

Based on the findings described above, particularly related to the analysis of the implementation effectiveness of SGIP, the authors make the following brief recommendations.

First, the design of the SGIP should be re-evaluated based on the relatively low level of applications over the past few years for the Non-Renewable part of the program. The combination of the requirements of the program, particularly for metering and reporting of system performance over time, and maintaining an 80+ capacity factor to realize full program benefits, appears to be factors in reducing the economic attractiveness of participating in the program.

Second, perform additional CHP market analyses to understand the key factor inhibiting CHP uptake, such as the imposition of utility standby and demand charges. Recent analysis has shown that these do have an important impact[37], where a relaxation of standby/demand charges could significantly expand CHP uptake. The authors believe that some level of standby charges are appropriate but need to be carefully considered along with the potential grid congestion relief and other benefits that CHP systems can provide.

Third, there is a relatively poor understanding among potential CHP "end user" groups that may adopt additional CHP systems in California of the latest utility interconnection, SGIP, and feed-in tariff program rules, as well as the agreements made by utilities and the CAISO to prioritize the procurement of CHP-based generation. Further efforts to harmonize and integrate these programs, as well as additional education and outreach efforts to publicize their potential positive impacts on CHP system economics, appear to be clearly needed.

Finally, further "stakeholder" summit meetings should be held to garner feedback from industrial groups and CHP vendors, manufacturers, and system integrators to better understand the market challenges facing CHP in California and how they might be best

[37] California Energy Commission. *2007 Net System Power Report.* CEC-200-2008-002, Sacramento: California Energy Commission, 2008. http://www.energy.ca.gov/2012publications/CEC-200-2012-002/CEC-200-2012-002-REV.pdf

addressed. While much progress has been made to make CHP systems easier to connect and commission, previous feedback from industry groups to the PCEAC has indicated that significantly issues and barriers still remain.

6.4 Conclusions

In conclusion, the CHP market in California continues to evolve in complicated ways. The combined impacts of evolving technologies, competing options and fluctuating fuel prices, and a complex and intricate policy and market environment creates a somewhat challenging environment for those in a position to adopt further CHP in the state. This study has indicated that different market segments in California have significant difference in terms of their basic energy use patterns that impact potential CHP system design and implementation. Identifying successful models for CHP adoption for specific market segments, through more careful study and further implementation experience with the latest technologies, could help to further develop these markets through the accumulation of "lessons learned" and development of best practices for system implementation and operation.

GLOSSARY

Term	Definition
$	U.S. dollar(s)
A	ampere
AB 32	Assembly Bill 32; the Global Warming Solutions Act of 2006
BTU	British thermal unit(s), a unit of energy
CAISO	California Independent System Operator
CEC	California Energy Commission
CEUS	California Commercial End Use Survey
CHP	combined heat and power
CO_2	carbon dioxide
CO_2e	carbon-dioxide equivalent
CPUC	California Public Utilities Commission
DER-CAM	Distributed Energy Resources Customer Adoption Model
DOE	U.S. Department of Energy
DX	Direct Expansion air conditioner (typical "roof top" packaged air conditioner)
EEA	Energy and Environmental Analysis, Inc.
EIA	Energy Information Administration
EMS	energy monitoring system
FERC	Federal Energy Regulatory Commission
FG	food/grocery industry
g	gram(s)
GHG	greenhouse gas
HRSG	heat-recovery steam generator
ICE	internal combustion engine
IEPR	Integrated Energy Policy Report
IOU	investor-owned utility
kbtu	1000 BTU
kW	kilowatt(s), a unit of power
kWh	kilowatt-hour(s), a unit of energy
LBNL	Lawrence Berkeley National Laboratory
MW	megawatt(s), a unit of power
MWh	megawatt-hour(s), a unit of energy
O&M	operations and maintenance
PCC	Pasadena City College
psia	pounds per square-inch absolute
PIER	Public Interest Energy Research
PURPA	Public Utility Regulatory Policies Act
PV	photovoltaic
RAEL	Renewable and Appropriate Energy Laboratory

RD&D	research, development, and demonstration
RPS	Renewable Portfolio Standard
SCAQMD	South Coast Air Quality Management District
Scf	Standard cubic foot (corrected volume @ 14.7 psia, 70 deg-F)
SGIP	Self-Generation Incentive Program
UC	University of California
UCB	University of California, Berkeley
UCDMC	University of California Davis Medical Center
UCI	University of California, Irvine
U.S.	United States
V	volt(s)
WECC	Western Electricity Coordinating Council
WHP	waste heat to power

APPENDIX A:
General CHP Technology Characterizations and Performance Improvement Forecasts

Year 2010 – Gas Reciprocating Engines (Constant Year 2010 $s)

Technology	Gas Reciprocating Engine	Gas Reciprocating Engine
Electric Capacity (kW)	1,000	2,000
Electric Heat Rate, HHV (Btu/kWh)	9,097	9,394
Electric Efficiency, HHV (%)	37.51%	36.32%
Fuel Input (MMBtu/hr)	9.097	18.788
Thermal Energy Output (MMBtu/hr)	3.920	8.800
Total CHP Efficiency (%)	80.60%	83.16%
Power to Thermal Output Ratio	0.871	0.776
Net Heat Rate (Btu/kWh)	4,197	3,894
Variable O&M Costs ($/kWh)	0.015	0.012
Fixed O&M Costs ($/kW-year)	40	25
Total Installed Costs ($/kW)	1600	1400
Equipment ($/kW)	910	885
Installation Labor/Materials ($/kW)	390	340
Engineering, Management, Permitting, Fees & Contingency ($/kW)	300	175

Year 2015 – Gas Reciprocating Engines (Constant Year 2010 $s)

Technology	Gas Reciprocating Engine	Gas Reciprocating Engine
Electric Capacity (kW)	1,000	2,000
Electric Heat Rate, HHV (Btu/kWh)	8,903	9,187
Electric Efficiency, HHV (%)	38.32%	37.14%
Fuel Input (MMBtu/hr)	8.903	18.375
Thermal Energy Output (MMBtu/hr)	3.961	8.863
Total CHP Efficiency (%)	82.81%	85.37%
Power to Thermal Output Ratio	0.862	0.770
Net Heat Rate (Btu/kWh)	3,952	3,648
Variable O&M Costs ($/kWh)	0.015	0.012
Fixed O&M Costs ($/kW-year)	40	25
Total Installed Costs ($/kW)	1448	1248
Equipment ($/kW)	824	789
Installation Labor/Materials ($/kW)	353	303
Engineering, Management, Permitting, Fees & Contingency ($/kW)	272	156

Source: Sentech, 2010 ("Reference Case").

Year 2030 – Gas Reciprocating Engines (Constant Year 2010 $s)

Technology	Gas Reciprocating Engine	Gas Reciprocating Engine
Electric Capacity (kW)	1,000	2,000
Electric Heat Rate, HHV (Btu/kWh)	8,592*	8,855*
Electric Efficiency, HHV (%)	39.71%	38.53%
Fuel Input (MMBtu/hr)	8.592*	17.710*
Thermal Energy Output (MMBtu/hr)	4.466	9.927
Total CHP Efficiency (%)	86.60%	89.16%
Power to Thermal Output Ratio	0.764	0.688
Net Heat Rate (Btu/kWh)	3,515	3,189
Variable O&M Costs ($/kWh)	0.015	0.012
Fixed O&M Costs ($/kW-year)	40	25
Total Installed Costs ($/kW)	872	672
Equipment ($/kW)	496	425
Installation Labor/Materials ($/kW)	213	163
Engineering, Management, Permitting, Fees & Contingency ($/kW)	164	84

Year 2035 – Gas Reciprocating Engines (Constant Year 2010 $s)

Technology	Gas Reciprocating Engine	Gas Reciprocating Engine
Electric Capacity (kW)	1,000	2,000
Electric Heat Rate, HHV (Btu/kWh)	8,492*	8,749*
Electric Efficiency, HHV (%)	40.18%	39.00%
Fuel Input (MMBtu/hr)	8.492*	17.498*
Thermal Energy Output (MMBtu/hr)	4.708	10.428
Total CHP Efficiency (%)	89.26%	91.82%
Power to Thermal Output Ratio	0.725	0.655
Net Heat Rate (Btu/kWh)	3,212	2,877
Variable O&M Costs ($/kWh)	0.015	0.012
Fixed O&M Costs ($/kW-year)	40	25
Total Installed Costs ($/kW)	640	440
Equipment ($/kW)	364	278
Installation Labor/Materials ($/kW)	156	107
Engineering, Management, Permitting, Fees & Contingency ($/kW)	120	55

Source: Sentech, 2010 ("Reference Case").
Note: "*" denotes a correction for an apparent mistake in the original source where there is a discrepancy between reported Electric Efficiency and Electric Heat Rate (HHV basis) for the 2030 and 2035 cases.

Year 2010 – Gas Turbines (Constant Year 2010 $s)

Technology	Gas Turbine	Gas Turbine (Recuperated)	Gas Turbine	Gas Turbine	Gas Turbine	Gas Turbine
Electric Capacity (kW)	3,510	4,600	5,670	14,990	25,000	40,000
Electric Heat Rate, HHV (Btu/kWh)	13,893	10,054	12,254	10,945	9,945	9,220
Electric Efficiency, HHV (%)	24.56%	33.94%	27.84%	31.17%	34.30%	37.00%
Fuel Input (MMBtu/hr)	48.764	46.248	69.480	164.006	248.625	368.800
Thermal Energy Output (MMBtu/hr)	25.102	14.012	34.298	74.933	90.770	128.791
Total CHP Efficiency (%)	76.04%	64.23%	77.21%	76.85%	70.70%	72.10%
Power to Thermal Output Ratio	0.477	1.120	0.564	0.683	0.940	1.060
Net Heat Rate (Btu/kWh)	4,953	6,246	4,693	4,696	5,427	5,180
Variable O&M Costs ($/kWh)	0.007	0.006	0.005	0.006	0.006	0.005
Fixed O&M Costs ($/kW-year)	22	14	12	9	10	7
Total Installed Costs ($/kW)	1,910	1,369	1,280	1,091	1,097	972
Equipment ($/kW)	1,130	832	826	751	701	640
Installation Labor/Materials ($/kW)	507	341	271	181	252	204
Engineering, Management, Permitting, Fees & Contingency ($/kW)	274	196	182	159	144	128

Source: Sentech, 2010 ("Reference Case").

Year 2015 – Gas Turbines (Constant Year 2010 $s)

Technology	Gas Turbine	Gas Turbine (Recuperated)	Gas Turbine	Gas Turbine	Gas Turbine	Gas Turbine
Electric Capacity (kW)	3,510	4,600	5,670	14,990	25,000	40,000
Electric Heat Rate, HHV (Btu/kWh)	13,893	10,054	12,254	10,945	9,945	9,220
Electric Efficiency, HHV (%)	24.56%	33.94%	27.84%	31.17%	34.30%	37.00%
Fuel Input (MMBtu/hr)	48.764	46.248	69.480	164.066	248.688	368.865
Thermal Energy Output (MMBtu/hr)	25.297	14.255	34.663	75.725	91.144	130.947
Total CHP Efficiency (%)	76.44%	64.76%	77.73%	77.33%	70.95%	72.50%
Power to Thermal Output Ratio	0.474	1.101	0.558	0.676	0.936	1.043
Net Heat Rate (Btu/kWh)	4,734	6,045	4,491	4,526	5,216	5,5036
Variable O&M Costs ($/kWh)	0.007	0.006	0.005	0.006	0.006	0.005
Fixed O&M Costs ($/kW-year)	22	14	12	9	10	7
Total Installed Costs ($/kW)	1,879	1,340	1,251	1,066	1,036	962
Equipment ($/kW)	1,111	815	808	734	662	634
Installation Labor/Materials ($/kW)	499	333	265	177	238	202
Engineering, Management, Permitting, Fees & Contingency ($/kW)	269	191	178	156	136	126

Source: Sentech, 2010 ("Reference Case").

Year 2030 – Gas Turbines (Constant Year 2010 $s)

Technology	Gas Turbine	Gas Turbine (Recuperated)	Gas Turbine	Gas Turbine	Gas Turbine	Gas Turbine
Electric Capacity (kW)	3,510	4,600	5,670	14,990	25,000	40,000
Electric Heat Rate, HHV (Btu/kWh)	13,893	10,054	12,254	10,945	9,945	9,220
Electric Efficiency, HHV (%)	24.56%	33.94%	27.84%	31.17%	34.30%	37.00%
Fuel Input (MMBtu/hr)	48.764	46.248	69.480	164.066	248.688	368.865
Thermal Energy Output (MMBtu/hr)	25.883	14.604	35.187	76.377	94.501	135.373
Total CHP Efficiency (%)	77.64%	65.51%	78.49%	77.73%	72.30%	73.70%
Power to Thermal Output Ratio	0.463	1.075	0.550	0.670	0.903	1.008
Net Heat Rate (Btu/kWh)	4,076	5,440	3,887	4,015	4,582	4,603
Variable O&M Costs ($/kWh)	0.007	0.006	0.005	0.006	0.006	0.005
Fixed O&M Costs ($/kW-year)	22	14	12	9	10	7
Total Installed Costs ($/kW)	1,730	1,254	1,165	965	915	922
Equipment ($/kW)	1,023	763	752	664	585	607
Installation Labor/Materials ($/kW)	459	312	247	160	210	194
Engineering, Management, Permitting, Fees & Contingency ($/kW)	248	179	166	141	120	121

Source: Sentech, 2010 ("Reference Case").

Year 2035 – Gas Turbines (Constant Year 2010 $s)

Technology	Gas Turbine	Gas Turbine (Recuperated)	Gas Turbine	Gas Turbine	Gas Turbine	Gas Turbine
Electric Capacity (kW)	3,510	4,600	5,670	14,990	25,000	40,000
Electric Heat Rate, HHV (Btu/kWh)	13,893	10,054	12,254	10,945	9,945	9,220
Electric Efficiency, HHV (%)	24.56%	33.94%	27.84%	31.17%	34.30%	37.00%
Fuel Input (MMBtu/hr)	48.764	46.248	69.480	164.066	248.688	368.865
Thermal Energy Output (MMBtu/hr)	26.078	14.605	35.188	76.266	96.118	136.849
Total CHP Efficiency (%)	78.04%	64.52%	78.49%	77.66%	72.95%	74.10%
Power to Thermal Output Ratio	0.459	1.075	0.550	0.671	0.888	0.998
Net Heat Rate (Btu/kWh)	3,857	5,239	3,685	3,845	4,371	4,459
Variable O&M Costs ($/kWh)	0.007	0.006	0.005	0.006	0.006	0.005
Fixed O&M Costs ($/kW-year)	22	14	12	9	10	7
Total Installed Costs ($/kW)	1,663	1,225	1,136	965	955	922
Equipment ($/kW)	983	745	734	664	610	607
Installation Labor/Materials ($/kW)	441	305	241	160	220	194
Engineering, Management, Permitting, Fees & Contingency ($/kW)	238	175	162	141	125	121

Source: Sentech, 2010 ("Reference Case").

APPENDIX B:
PCEAC DER-CAM Modeling Inputs

Data Needs

- Hourly Electricity, Heating, Cooling, Domestic Hot Water, etc. demand for selected commercial buildings and hospitals
- Electricity and NG tariffs
- Technology performance data and costs
- Offset CO_2 emissions: Average (Hourly), marginal (Hourly), and displaced facility
- Weather and solar radiation (unless disallow PV and solar thermal as technology options)

Collected Data

Building Load Data

CEUS

The California Commercial End Use Survey (CEUS) is a comprehensive survey of energy use in the commercial sector. The survey encompasses 2,800 facilities from the service territories of California Investor Owned Utilities (IOU's). As part of the CEUS data collection effort, calibrated building energy use simulation models were developed based on the collected survey data.

Data used for this modeling effort are hourly loads presented in a 16 day-type format, consisting of representative loads for 4 days in each season (Hot, Cold, Average and Weekend in Spring, Summer, Fall and Winter). The CEUS stratifies results by building type, which each category further broken down by Size strata cut-points based on annual energy usage detailed below.

Table B-1: Building Type Size-Strata Cut-points

Building Type	Cutpoints (Annual kWh)		
	Small	Medium	Large
1. Small Office	< 15,000	15,000 to 100,000	>= 100,000[3]
2. Large Office	< 2,000,000	2,000,000 to 4,750,000	>= 4,750,000
3. Restaurant	< 90,000	90,000 to 315,000	>= 315,000
4. Retail Store	< 80,000	80,000 to 900,000	>= 900,000
5. Food/Liquor	< 190,000	190,000 to 1,600,000	>= 1,600,000
6. Unrefrigerated Warehouse	< 85,000	85,000 to 1,000,000	>= 1,000,000
7. School	< 250,000	250,000 to 1,000,000	>= 1,000,000
8. College	< 400,000	400,000 to 3,750,000	>= 3,750,000
9. Health Care	< 450,000	450,000 to 3,000,000	>= 3,000,000
10. Hotel	< 300,000	300,000 to 2,200,000	>= 2,200,000
11. Misc	< 30,000	30,000 to 500,000	>= 500,000
25. Refrigerated Warehouse	< 500,000	500,000 to 3,000,000	>= 3,000,000

This study focused on the Small Office (<30,000 ft^2) and Large Office (>30,000 ft^2) building types, comparing the distributed energy investment decision for a typical structure from within each energy cut-point from the aggregated CEUS data.

The publically available CEUS dataset does not contain load shapes for individual examples within each building type; only aggregate load shapes and end-use energy intensities are provided for the survey results. Representative load shapes based on the floor space for small and large office structures for modeling in DER-CAM, and normalized for total annual energy use were generated using the energy-use intensities provided.

ENERNOC OpenData Customer Load Data

In March, 2013 EnerNOC, Inc. released customer energy use data for 100 sites as part of their Open Data initiative under a Creative Commons non-commercial license. The data has been scrubbed and anonymised and covers a range of Building Types in different IOU Service territories. The data is provided at a resolution of 5 minutes, and will be used to help verify the results from DER-CAM using the CEUS dataset. Two commercial sites from California were selected to provide this validation: Site 22, a commercial site with 318,130 ft^2 of floor space in PG&E's forecasting climate zone 5, and Site 31, a commercial site with 294,651 ft^2 floor space located in SCE's forecasting climate zone 8. Sites representing the small office building type and other annual energy use cut-points were not included as they are represented in the customer data released by EnerNOC, Inc.

PG&E and SoCal Edison Static and Dynamic Building Load Data

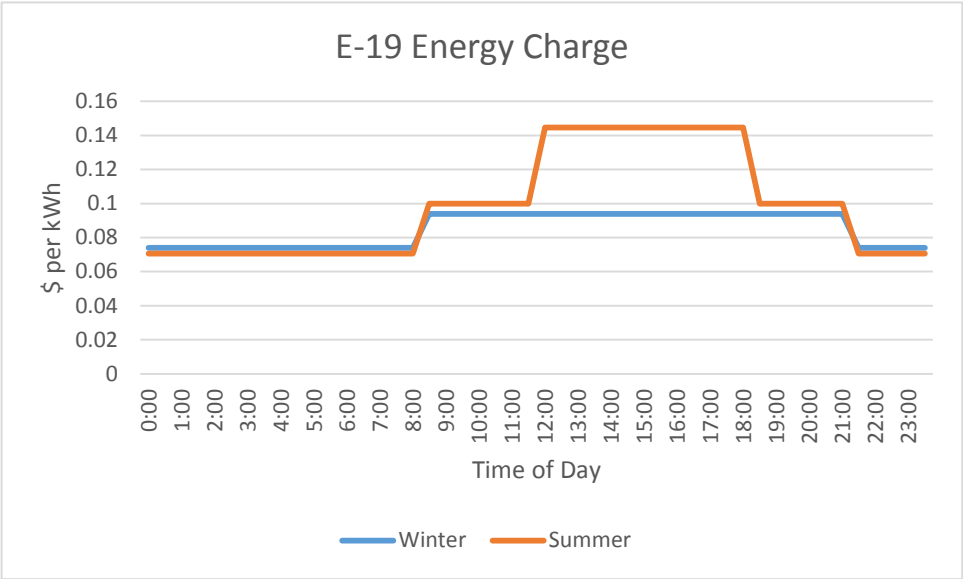
As part of company regulatory filings, IOU's in California publish sample baseline load profiles for different customer classes. These load profiles can be used to model the investment decision for distributed generation systems; however, they are limited in their application as they aggregate all electricity and gas usage, and do not describe the hourly end-use breakdown of energy usage in different customer classes.

Tariffs and Incentives

Example: PG&E Service Territory

For small (<30,000 ft²) structures, the E-19 tariff was selected for model structures in the PG&E service territory. The E-19 tariff for commercial customers who do not meet the requirements of the E-20 tariff, and whose maximum monthly demand is greater than 499 kW for 3 months of the year. The E-19 tariff has provisions for Standby service in the case of the customer receiving energy from non-utility sources (e.g. distributed generation). The E-19 tariff also places customers on a Peak Day Pricing (PDP) structure, unless they opt out to a time of use (TOU) rate. The TOU Charges are summarized below in Figure B-1.

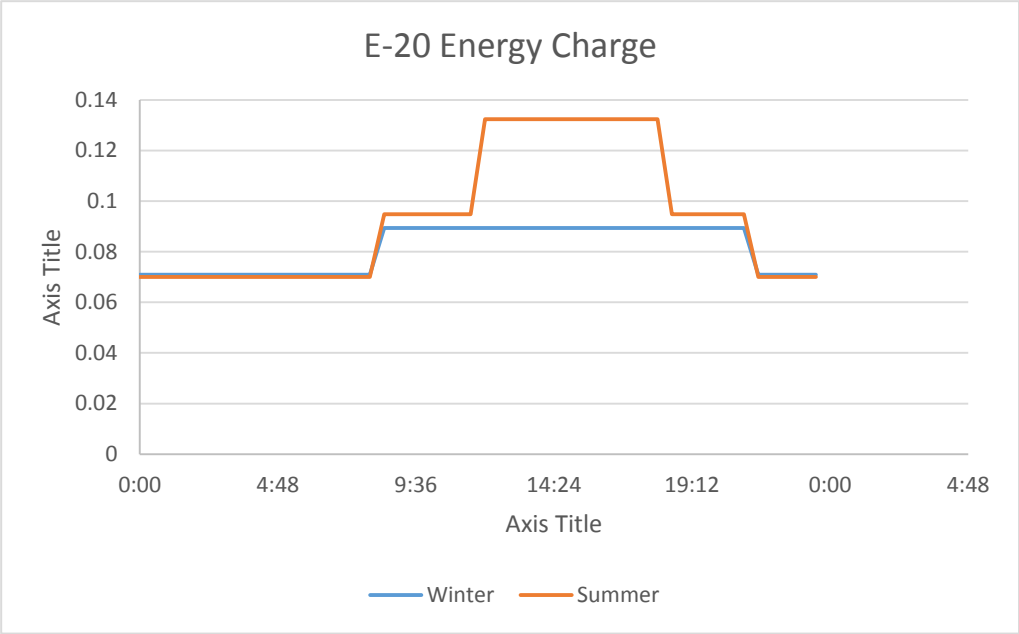
Figure B-1: PG&E Service Territory E-19 Tariffs



In addition to the demand charges, the E-19 tariff also includes a TOU demand charge, which levies a flat rate for the maximum demand within the peak and off-peak periods, and a demand charge for the maximum demand at any time during the month, as well as a Peak-Day-Pricing (PDP) charge for energy consumed during periods of anticipated high total system demand.

For Commercial customers with monthly energy demand greater than 1000 kW for greater than 3 months of the year, the E-20 tariffs are applied, shown in the figure below.

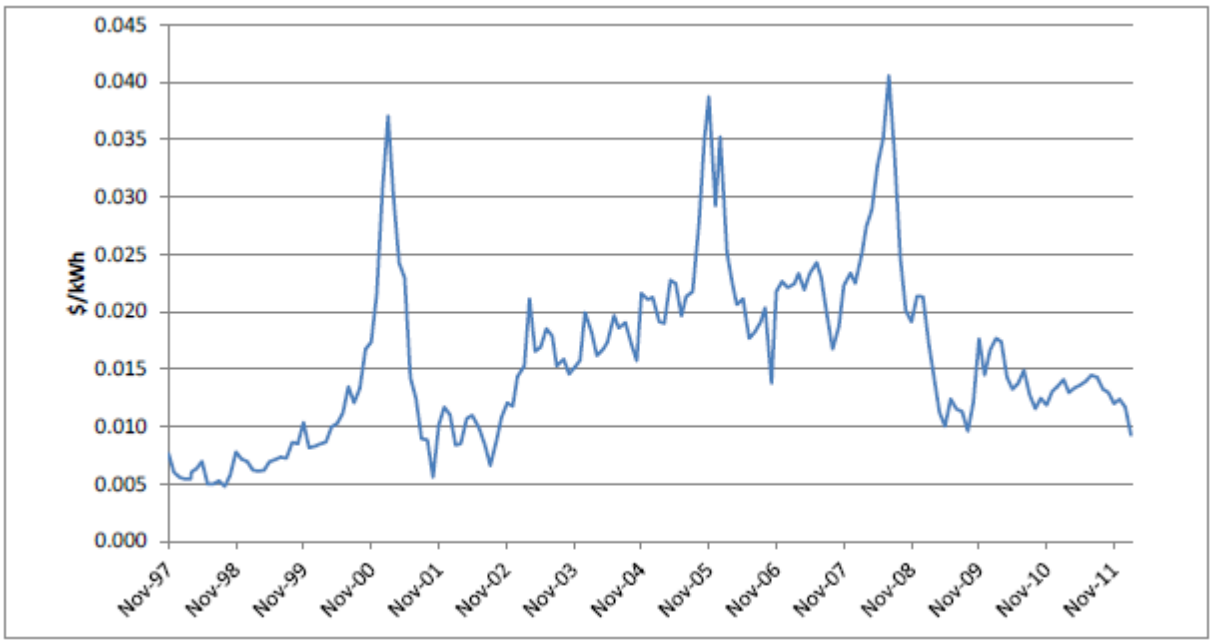
Figure B-2: PG&E Service Territory E-20 Tariffs



Natural Gas Tariffs

The natural gas prices charged to commercial customers was taken from the rate structure published by the utility in which a given site is located. If a special rate is provided for facilities operating CHP plants, these rates were included in the model. To account for the projected changes in natural gas prices, natural gas price projections published by utilities were used for future years. The recent price of natural gas has been volatile, illustrated below in Figure B-3, making projections for natural gas prices uncertain. Sites can manage this risk by signing futures contracts and long-term natural gas contracts, however this is not considered in our analysis.

Figure B-3: Weighted Average Cost of Natural Gas, PG&E Service Territory[38]



[38] PG&E Corporation, Public Data, 2012.

SGIP Incentives

This report considered the impact of having SGIP funds available for qualifying CHP facilities. The regulations governing qualifying CHP facilities are summarized in the latest SGIP handbook[39] published by the CPUC, and made available by California investor owned utilities.

The SGIP provides a hybrid performance based incentive that rebates the cost of a qualifying installation on a per-kW capacity basis. The incentive is paid out over 5 years, and is adjusted based on a facilities' ability to meet GHG emissions criteria, and specified minimum capacity factors. The maximum available incentives for 2013 are summarized below in Table B-2; per D.11-09-015 incentives will decrease by 10% each year thereafter until the sunset of the program. A facility will receive 50% of the incentive paid up-front, with the remainder paid over 5 years if capacity factor requirements are met. In DER-CAM, a system will still qualify for incentives if the capacity is less than 80%, however the performance-based incentive will be reduced accordingly.

Table B-2: 2013 SGIP Incentive Levels

TECHNOLOGY	INCENTIVE LEVEL ($/W)
COMBUSTION BASED CHP	0.48
ADVANCED ENERGY STORAGE	1.80
FUEL CELL (CHP OR ELECTRICITY ONLY)	2.03

[39] California Public Utilities Commission *2013 Self-Generation Incentive Program Handbook*, February 1, 2013.

AB1613 Feed In Tariffs

The California legislature approved AB 1613, requiring IOU's to provide a standardized PPA to purchase electricity from qualifying CHP facilities. The prices paid to producers under these standardized contracts is based on the Market Price Referent, which is adjusted monthly to track the prices of natural gas. This report used the historical published PPA prices paid by each IOU for facilities within their service territory[40]. The last year for which monthly figures is 2012; these prices are somewhat lower than projected prices due to increases in wholesale natural gas prices.

GHG Allowances and Costs

As set forth in AB 32, California has statewide mandates to decrease emissions of GHG's by the year 2020. Authority to develop cost effective measures to reach these goals was given to the Air Resources Board (ARB), which implemented a Cap-and-Trade market to reduce emissions from covered entities. The program took effect in 2012, and the first compliance obligation began on January 1, 2013. Compliance is based on the concept of "first-deliverer". The entity that first brings a product with associated greenhouse gas emissions into the California market has the compliance obligation. For example, in the California wholesale electricity market, if the generator is located within California they must purchase allowances, and for imported electricity, the entity that first handles the transaction of electricity into the CA market is responsible for compliance.

If an entity has a compliance obligation, the covered entity must bid on allowances that permit the emission of 1 metric ton of CO_2e within the compliance year. Under the first compliance period (from 2013 to 2015) entities that emit less than 25,000 metric tons of CO_2e each year do not have compliance obligations. For CHP facilities, this is approximately the level of emissions that would result from a 5 MW gas turbine operating near capacity. In 2015, however, the carbon market will expand to encompass most of the California economy, with most CHP sites will having a compliance obligation.

This project included optimization runs that account for the current settlement price and futures contract settlement price to assess the impact compliance may have on the adoption of CHP. The results of allowance auctions are published by the California Air Resources Board.[41]

[40] http://www.pge.com/b2b/energysupply/qualifyingfacilities/prices/

[41] See: http://www.arb.ca.gov/cc/capandtrade/auction/auction.htm

Technology Cost and Performance

The technology cost and performance projections for CHP equipment options is based on data published in the EPA CHP catalogue of technologies. While gas turbines and internal combustion turbines are relatively mature technologies, micro-turbines and high temperature fuel cells are anticipated to have significant cost reductions as the technologies and market matures; a summary of technology costs for 2013 and projected costs in 2020 is included below in Table B-3.

Table B-3: Summary of DG and CHP equipment costs Assumed in DER-CAM Runs

TYPE	CAPACITY (KW)	2103 COST ($/KW)	2020 COST ($/KW)
ICE-HX	60	3580	3580
ICE-HX	250	2180	2180
GT	1000	2580	2580
MT – SM	60	3610	2217
MT – MD	150	2940	1776
FC –SM	100	3990	2270
FC – MD	250	2700	1719
FC – SM, HX	100	3580	3580
FC – MD, HX	250	2180	2180

CO2 Emissions

Average Bulk Grid CO2

All runs calculated the CO_2 emissions reductions for CHP facilities compared the estimated average bulk grid CO_2 emissions from the current year (2013) through the sunset of the current SGIP program (2016). Average CO_2 emissions were calculated by dividing the total greenhouse gas (GHG) emissions, given in CO_2 equivalents, by total sales of electricity within the California market.

Long Term Displaced Facilities

Under long term planning horizons it can be argued that the marginal facility displaced by investments in CHP and district energy is the combined cycle gas turbine.[42][43] The marginal displaced emissions of a combined cycle gas turbine is estimated to be 363 g/kWh.[44]

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[42] Heath G.A. and Nazaroff W.W. "Intake-to-Delivered-Energy Ratios for Central Station and Distributed Electricity Generation in California," *Atmospheric Environment* 33: 4535-4564, 2007.

[43] Strachan, Neil, and Alexander Farrell, "Emissions from Distributed Vs. Centralized Generation: The Importance of System Performance," *Energy Policy* 34 (17): 2677–2689, 2006.

[44] Strachan and Farrell, 2006.

APPENDIX C:
Analysis of Full and Incremental SGIP Metering Costs for Example CHP Systems

Summary

The purpose of this assessment is to characterize the range of costs associated with electricity, fuel, and thermal metering of combined heat and power (CHP) systems installed in California with support from the California Self-Generation Incentive Program (SGIP). Such metering is required for performance monitoring of systems to assure that they are meeting the minimum program efficiency requirements, as well as achieving the expected capacity factors over the 5-year payout term of the SGIP incentive payments. costs range from about $8,500 to $70,000 for systems sized from 60 kW to 10+ MW. Costs are predominantly driven by metering technology selection for fuel and heat recovery, along with the complexity of installation.

Introduction

The current SGIP, authorized under Senate Bill 412, provides incentives for the deployment of qualified high-efficiency and emerging technology distributed generation systems. Current program funding is available for systems that are installed through 2016. As described in the 2012 SGIP Handbook, a hybrid performance-based incentive (PBI) is now used to structure payments to program participants based on meeting or exceeding electrical output (capacity factor) and greenhouse gas emissions (GHG) benchmarks.[45] Using this structure, 50% of the incentive funds are paid in a lump sum to program participants upon project completion, with the remainder paid over a 5-year performance period. If minimum performance criteria are met – an 80% capacity factor and no more than 398 kg of carbon dioxide per MWh - 100% of funds are received by the end of the 5-year period; exceeding the criteria results in the full incentive being received sooner, with under-performance leading to decreased payments each year performance targets are underachieved.

In addition, with the exception of some stationary fuel cell systems that can qualify based on electrical efficiency alone, all systems installed under the current program must utilize some form of waste heat recovery to qualify for incentive payments. The exact amount can vary relative to system electrical efficiency and site-specific factors, but must be sufficient such that the total system efficiency meets or exceeds 60%.[46] Alternatively, fuel cell systems can qualify based on electric-only efficiencies of 40% or greater, with or without additional waste heat

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[45] California Public Utilities Commission, California Self-Generation Incentive Program Handbook, 2012, http://www.cpuc.ca.gov/NR/rdonlyres/A821B0B1-4D8B-44FB-A5C5-07F1BD6A53BE/0/SGIP_Handbook2012_v23.pdf

[46] System Efficiency = $(T+E)/F_{HHV}$; E = System Rated Electric Capacity converted to Btu/hr; T = System useful waste heat recovery rate in Btu/hr at rated capacity; F_{HHV} = System Fuel consumption rate reported in HHV at rated capacity.

recovery. All qualifying systems must also meet minimum requirements for emissions of oxides of nitrogen of 0.07 pounds per MWh or less.

Due to the performance benchmarks under SGIP and the need to track program performance, systems qualifying for SGIP funds are required to also install extensive metering infrastructure. At the minimum, these systems must meet sub-metering requirements to obtain the following data:

- Useful electrical output minus any parasitic loads;
- Useful thermal output downstream any parasitic loads; and
- Fuel consumption downstream of other fuel uses than the CHP installation.

The meters for each of the three data streams must also meet minimum specific requirements, summarized below.

Electrical Meters:

- Provide at least 15-minute interval data on all required generator performance/output data points.
- Accuracy of +/- 2% on actual system output.
- Tested according to ANSI C-12 protocols for measurement of power and energy.
- Certified by independent testing body.
- Communications and Data Transfer protocols allowing PDP to communicate with meter and obtain required data. Data must have capability to report remotely, on a daily basis.
- Display showing meter's measured net generated energy output and measured instantaneous power.
- Capability to store 7 days of data in the event of a power outage.
- Meters must measure delivered energy by having a meter at the output of the generator, and after power delivery to all parasitic loads (e.g., with multiple meters or a meter with multiple channels). On-board meters must have additional channels to measure parasitic energy consumption.

Thermal Meters:

- Thermal Meters are required for non-renewable fuel systems with waste heat capture and capacities greater than 30 kW.
- Must provide at least 15-minute interval data on required performance parameters.
- Specific instrumentation will vary by application, but must be sufficient to measure useful thermal energy production.
- Accuracy must be within +/- 5% at design conditions, for both on-board and external metering systems. Maintenance plans must be filed to guarantee compliance within the PBI period.
- Must report useful thermal production in MBTU/hr. Heat transfer fluid specific heat and density must be reported at commissioning.
- Communications and Data Transfer protocols allowing PDP to communicate with meter and obtain required data. Data must have capability to report remotely, on a daily basis
- Capability to store 7 days of data in the event of a power outage.

- Proposed meter and sensor locations must be identified for each individual project. For combined cooling, heating and power it is recommended that chilled water output be measured.

Fuel Metering:

- Provide at least 15-minute interval data on required performance parameters.
- Specific instrumentation may vary by application and installation, but measurements are commonly taken by one of the following:
    - Mass Flow
    - Continuous differential pressure across an orifice
    - Utility gas meter
- Accuracy must be within +/- 5% at design conditions, for both on-board and external metering.
- On board meters must be able to measure fuel consumption by the generator.
- Communications and Data Transfer protocols allowing PDP to communicate with meter and obtain required data. Data must have capability to report remotely, on a daily basis
- Capability to store 7 days of data in the event of a power outage.
- For external fuel meters, acceptable metering data points are before fuel entry into the generator, but downstream of any other loads. For On-board meters, fuel use must be metered prior to any fuel consumption by the generator.

Additional guidelines

All SGIP projects must select a Performance Data Provider (PDP). PDPs are third parties contracted to collect, store, and report telemetry data from all required metering points. Qualifying entities are subject to further rules and guidelines of the SGIP program, and program administrators maintain up-to-date lists of approved service providers that may perform as PDP's. A list of current approved providers is maintained on the California Center for Sustainable Energy website.[47]

Estimated Metering Costs

Metering costs for grid-connected energy projects can vary greatly by equipment selection and application, and are subject to system size, meter technology selection, metering point selection, and tolerances for electrical ratings and fluid pressures and temperatures. As a result, there are large variances in the reported costs for meters satisfying SGIP requirements. Costs are categorized into the following areas relevant to SGIP projects using PDPs for data collection and reporting (in the "Recurring" costs category):

- Capital Costs
    - Meter purchase
    - Ancillary devices (current transmitters, thermocouples, etc.)

[47] http://energycenter.org/index.php/incentive-programs/self-generation-incentive-program/performance-data-providers

    - Communications
    - Miscellaneous supplies

- Labor (planning, prep, travel, installation of all hardware, connection of communications, operational testing, inspection, service shut-downs, trenching, etc.)
- Recurring
    - Communications fees
    - Data collection/storage
    - Data analysis
    - Operations and maintenance

Due to the various metering options and technologies available within the guidelines of the SGIP program, the survey of metering costs focused on the aggregated capital, labor, and recurring costs associated with each of the three data streams required.

Marginal costs for SGIP metering

When a CHP system is procured from a supplier, the system is generally built to specifications defined in agreement with the customer. Standard specifications representing the base costs for most systems typically include metering for electrical output and fuel consumption, with thermal energy recovery metering being more optional (but required for participation under the SGIP program). Estimated below are both the full expected costs of metering and the "marginal" costs associated with fully complying with SGIP requirements beyond what would be expected in a typical installation.

Marginal Costs for Electrical Metering

Revenue-grade meters are required for all CHP installations, and no significant cost differential was found for electrical metering for systems eligible for SGIP funds compared to those that would be included in a standard CHP installation.

Marginal Costs for Useful Waste Heat Recovery (UWHR)

Metering for useful waste heat recovered (UWHR) is an optional specification for some suppliers, and not typically included unless desired by the customer. However, UWHR metering is required by SGIP for CHP systems of over 30 kW. For some installations that would have otherwise included basic UWHR capability, the marginal cost of metering for SGIP eligibility is the cost differential between a basic meter without remote sensing capabilities, telemetry, and data storage, and a meter satisfying SGIP requirements. However, since metering for UWHR is not a standard specification for all systems, it was assumed here that the full cost of the UWHR meter is the marginal additional cost for SGIP compliance. also note that ultrasonic meters are possible for unique installations with special requirements for metering that is non-invasive; they are considered here for comparison to other commonly used meter types without these installation restrictions.

Marginal Costs for Metering Fuel Consumption

Metering for fuel consumption is standard but fuel metering with the accuracy, telemetry and data collection capabilities to meet SGIP requirements is not standard. Included in our estimates

below are the incremental costs of meters capable of SGIP requirements. Cost estimates for both types are shown in the detailed tables in the Appendix.

Marginal Costs for Meter Installation

The marginal installation cost of new meters is negligible for the installation of most new CHP systems, provided that there are allowances to provide the necessary utilities required for the meters. Unique and/or difficult configurations will result in higher installation costs for meters, not assumed in our base case assumptions but depicted below (Table 3) to show the potential system economic impacts. General costs for installation of meters (e.g. for retrofit or data collection prior to implementation of CHP) are discussed further below.

Metering Cost Data Collection

A set of meter cost data was collected from a variety of sources. Where available, costs for metering were collected from published reports and existing surveys. These reports generally focused on revenue-grade electricity meters as required for bidding into power markets, or participation in demand response programs. A survey of PDPs, metering equipment providers, and metering service providers was also conducted to determine the approximate installed costs for electricity, fuel, and thermal metering. All costs were compared against estimated costs reported in the RS Means catalogue of costs when appropriate matching cost categories were found. RS Means is a construction cost database used for estimation and planning.[48]

Challenges for Data Collection

Collecting reliable cost data for metering systems required under the SGIP program was hindered by the large variance in costs for metering useful thermal output and fuel use. While the costs for revenue-grade electricity metering do not scale with system size within wide size ranges, thermal and fuel metering costs are affected by various factors that include meter technology selection, pipe diameters, heat transfer fluid pressures and temperatures, and fuel pressures.

Costs associated with installing metering are affected by the availability of existing infrastructure for telecommunications and power, as well as the complexity of the installation. Meters installed as part of new construction typically have lower installation costs than meters installed as part of retrofits to existing building mechanical systems, or with complex installations. Due to these factors, labor costs for meter installations can vary by an order of magnitude between installations. Fuel metering may have fewer variances in cost if CHP systems are provided with the option of on-board fuel metering. The sensitivity of cost data as a competitive advantage has also resulted in some respondents being reluctant to share cost data publicly.

Metering Cost Data Summary

Given a large amount of existing examples, and the low variation in installation costs, cost estimates for electrical metering have the least variation and are most certain. Fuel metering

[48] http://rsmeans.reedconstructiondata.com

costs are more variable, with the most influential variable for cost being the natural gas supply pressure. Metering useful thermal output has the highest variability, due to multiple options for meter types, various options for heat transfer fluids, and multiple options for metering points. The average costs for fuel and thermal metering only include costs for in-line fuel and thermal metering. Ultrasonic meters, an emerging but still high-cost option limited to single-phase heat transfer fluids, are not included in the average costs. Expected capital costs for ultrasonic meters can range from $15,000 to $45,000. Costs for fuel and heat transfer fluid meters also increase with pipe size, with costs for meters on small diameter pipe generally being lower.

Summaries of capital costs for the full range of sizes of electrical, thermal, and fuel meters are provided in Table 1 and Table below, with detailed estimates provided in Appendix Table A-1. The lower estimates are more typical of smaller system installations (100 kW – 1MW) and the higher estimates are more applicable to larger installations (5+ MW). Various types of meter costs are shown in more detail below for example 1 MW and 10 MW installations.

Table C-1: Metering Capital Cost Summary ($s U.S.)

	High	**Low**	**Average**
Electrical	$ 5,400	$ 900	$ 2,061
Heat	$ 7,909 *	$ 4,467	$ 5,491 **
Fuel	$ 12,725 *	$ 3,020	$ 6,288 **
Total	$ 26,034	$ 8,387	$ 13,840 **

* Highest cost meter is solid-state in-line where cheaper options may be available

** Does not include costs of non-invasive ultrasonic meters that are discussed separately

Table C-2: Marginal Metering Cost Summary ($s U.S.)

	High	**Low**	**Average**
Electrical	$ 0	$ 0	$ 0
Heat	$ 7,909	$ 4,467	$ 5,491
Fuel	$ 1,610	$ 230	$ 628
Total	$ 9,519	$ 4,697	$ 6,119

Installation costs for meters are much more variable, subject to the requirements of each individual location. Respondents indicated that for larger systems, the costs for installation can range from $50,000 to $100,000; however, installation costs can be much lower for simple

installations, or installations with existing conduit or utilities for meters. Telecommunications fees can range from $30 to $50 per month; separate from the recurring cost of contracting with a PDP for data acquisition, storage, and reporting.

In our survey of PDPs, service costs were not provided as this was considered sensitive information due to the emerging market for this service. As more PDPs enter the market, these cost data should become more available.

Comparison of Metering Costs with Total System Installation Costs

To provide context for the proportion of total system costs that can be attributed to the full costs of metering, the costs of metering are compared to total estimated system costs reported in the U.S. Environmental Protection Agencies CHP catalogue of technologies. The installed metering costs for a 1 MW and a 10 MW gas turbine CHP system are examined with regard to variation in thermal metering for a variety of fuel metering types and piping diameters, and under low and high installation cost assumptions. Note that the incremental costs of metering for SGIP compliance represents a portion (as shown in Tables 1 and 2) of these total metering system costs.

Table C-3: Example Installed Metering Cost as Percentage of Total System Cost and By Thermal Metering Strategy

	1 MW Gas Turbine System, % of System Cost			10 MW Gas Turbine System, % of System Cost		
	No installation cost	Low installation cost	High installation cost	No installation cost	Low installation cost	High installation cost
Low pressure NG, in-line thermal BTU metering <6″ diameter pipe	0.34%	1.85%	3.35%	0.09%	0.47%	0.86%
Low Pressure NG, non-invasive thermal BTU metering, <6″ diameter pipe	0.60%	2.10%	3.60%	0.15%	0.54%	0.92%
Low pressure NG, in-line thermal BTU metering >6″ diameter pipe	0.34%	1.85%	3.35%	0.09%	0.47%	0.86%
Low Pressure NG, non-invasive thermal BTU metering, >6″ diameter pipe	0.75%	2.25%	3.76%	0.19%	0.58%	0.96%
High pressure NG, in-line thermal BTU metering <6″ diameter pipe	0.85%	2.36%	3.86%	0.22%	0.60%	0.99%
High Pressure NG, non-invasive thermal BTU metering, <6″ diameter pipe	1.11%	2.61%	4.12%	0.28%	0.67%	1.05%
High pressure NG, in-line thermal BTU metering >6″ diameter pipe	0.85%	2.36%	3.86%	0.22%	0.60%	0.99%
High Pressure NG, non-invasive thermal BTU metering, >6″ diameter pipe	1.26%	2.76%	4.27%	0.32%	0.71%	1.09%

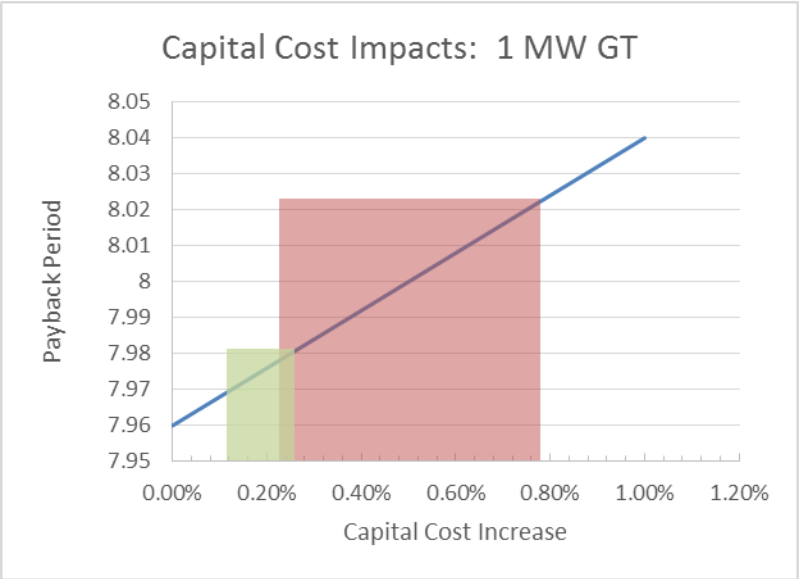
As shown in Table , approximate metering costs in the low and high installation cost assumption cases range from 1.9% to 4.3% of total system costs for a 1 MW system, and between 0.50% and 1.1% for a 10 MW system. Assuming highest and lowest metering costs for each system, the impacts to hypothetical system payback period are as shown in Table C-4 below.

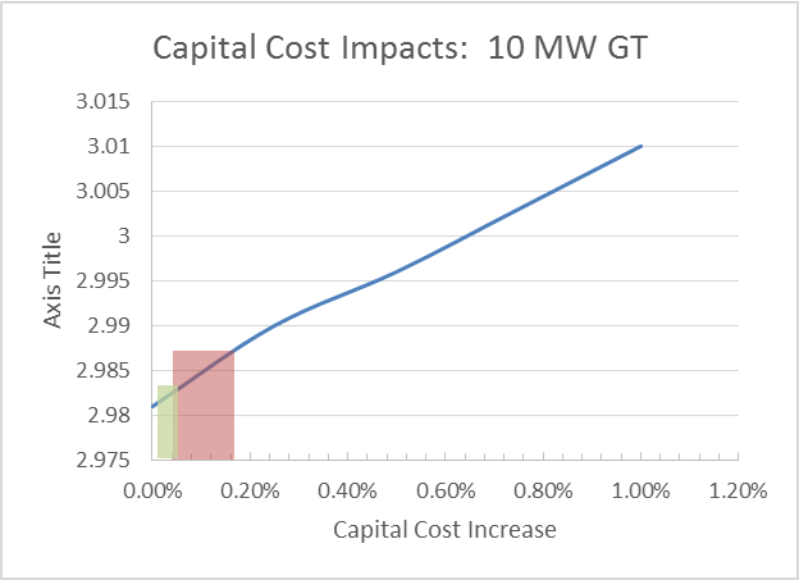
Table C-4: System Simple Payback Period Impacts of Full Metering Costs (years)

	No Metering	Low Costs	Average Costs	High Costs – In-Line Meters	High Costs – Non-Invasive
1 MW Gas Turbine System	7.96	8.10	8.17	8.26	8.30
10 MW Gas Turbine System	2.98	2.99	3.00	3.00	3.01

As shown in Figure 1, the impacts on payback period are more significant when the full costs of metering are added to example 1 MW and 10 MW projects than when just the incremental costs for SGIP compliance are considered. The impact on payback period of even the full costs of metering is small on the example 1 MW system and almost negligible for the example 10 MW system.

Figure C-1: System Simple Payback Period Impacts of Incremental SGIP Metering Costs (years)





Range of Total Capital Cost Impacts

Range of Incremental Cost Impacts

Under the same basic assumptions (see Appendix for details), metering costs have a proportionally greater impact on simple payback period for a 1 MW gas turbine compared to a

10 MW gas turbine. This impacts adds up to a few months in payback time for the 1 MW size systems but is essentially "lost in the noise" of the total costs associated with a 10 MW project. While the costs of metering scale with system size to some extent, this is predominantly due to piping size for heat transfer fluids (thermal metering), and the natural gas supply pressure for the CHP unit (fuel metering), and do not scale directly with system size, especially for larger systems. As a result, as system nameplate capacity increases, metering accounts for a lower proportion of costs. This also means that larger systems are less sensitive to variation in metering costs, with smaller systems being more exposed to risk in higher than expected metering costs.

Conclusions

In conclusion, the average CHP system metering capital costs range from $8,500 to $70,000, with installation adding a highly variable amount that can range from a few thousand dollars for smaller systems to $50,000 or more for larger and more complex installations. The marginal costs of metering for the SGIP program, however, are much lower, ranging from $7,487 to $20,634. The marginal costs of metering are primarily driven by the requirement for metering useful waste heat recovered. For complex installations, or systems where existing infrastructure for metering is not currently available, total installed metering system costs can be quite high, even where SGIP compliance is not at issue.

Under low and high cost scenarios, the additional cost burden of metering increased the expected payback period of a 1 MW gas turbine by about 4%, and a 10 MW system by less than 1%. However, even under the high cost scenario the additional cost of metering generally does not negate the much greater beneficial economic impacts of receiving SGIP incentives. For an example, 1 MW system, the maximum SGIP incentive payment is $500,000 without the biogas adder, and the highest anticipated cost of metering is approximately $120,000. For a 10 MW system, the maximum SGIP incentive payment is $875,000, and the highest anticipated metering cost is similar at about $150,000. For systems requiring electric-only metering (such as electricity-only fuel cell systems), the cost impacts are much lower, with total meter equipment costs under $2,500 and negligible marginal cost increases over basic metering requirements.