Edmund G. Brown, Jr.
Governor

Pacific Region Combined Heat and Power Application Center

PIER FINAL PROJECT REPORT

Prepared For:
California Energy Commission
Public Interest Energy Research Program

Prepared By:

PACIFIC REGION
COMBINED HEAT & POWER
APPLICATION CENTER

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FED-03-015

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The authors also thank the many other people who provided information and permissions needed for the project profiles to be developed. The authors alone are responsible for the contents herein.

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Preface

The California Energy Commission's Public Interest Energy Research (PIER) Program supports public interest energy research and development that will help improve the quality of life in California by bringing environmentally safe, affordable, and reliable energy services and products to the marketplace.

The PIER Program, conducts public interest research, development, and demonstration (RD&D) projects to benefit California.

The PIER Program strives to conduct the most promising public interest energy research by partnering with RD&D entities, including individuals, businesses, utilities, and public or private research institutions.

PIER funding efforts are focused on the following RD&D program areas:

- Buildings End-Use Energy Efficiency
- Energy Innovations Small Grants
- Energy-Related Environmental Research
- Environmentally Preferred Advanced Generation
- Energy Systems Integration
- Industrial/Agricultural/Water End-Use Energy Efficiency
- Renewable Energy Technologies
- Transportation

Pacific Region Combined Heat and Power Application Center is the final report for the Pacific Combined Heat and Power Regional Application Center Network project (Contract Number FED-03-015) conducted by UC Berkeley, UC Irvine, and San Diego State University. The information from this project contributes to the Environmentally Preferred Advanced Generation Program.

For more information about the PIER Program, please visit the Energy Commission's website at www.energy.ca.gov/research or contact the Energy Commission at 916-654-4878.

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Abstract

This project presents a summary of the tasks completed by the Pacific Region Combined Heat and Power Application Center through September 30, 2008, and an overview of the tasks planned for a subsequent phase of the project. The center, established in 2004, received funding for initial operations in late 2005. Its core funding originates with the U.S. Department of Energy and is awarded through the California Energy Commission Public Interest Energy Research Program through a State Energy Program grant.

The Pacific Region Combined Heat and Power Application Center features a collaborative structure among University of California, Berkeley, University of California, Irvine, and San Diego State University. Each university provides some unique capabilities and resources to the center. The primary groups involved on the three campuses are the Energy and Resources Group at University of California, Berkeley; the Advanced Power and Energy Program at University of California, Irvine; and the Industrial Assessment Center at San Diego State University.

This project benefits California as it addresses the ongoing need to promote combined heat and power in the Pacific region as an energy efficiency, cost containment, and environmental strategy. The project also provides stakeholders in the region with the best possible information to face the significant challenges as important policies are evolving rapidly, and energy prices and air quality regulations provide complications to the installation of combined heat and power in the region.

Keywords: Combined heat and power, CHP, combined cooling, heating and power, distributed generation, pacific region combined heat and power application center, PRAC

Executive Summary

Since its inception in 2004 and formal launch in late 2005, the Pacific Region Combined Heat and Power Application Center has been engaged in a wide array of combined heat and power and other distributed generation and "microgrid" system education and outreach, project screening/support, policy analysis, and regional and national networking activities. Completed and planned future activities are summarized below, following a brief history of the Pacific Region Combined Heat and Power Application Center and a summary of its operational structure.

The Pacific Region Combined Heat and Power Application Center received funding for initial operations in late 2005. Core Pacific Region Combined Heat and Power Application Center funding originates with the United States Department of Energy and is awarded to the Pacific Region Combined Heat and Power Application Center through a State Energy Program grant from the California Energy Commission Public Interest Energy Research Program.

Current combined heat and power systems involve the custom integration of disparate pieces (prime mover, generator, controls, heat recovery, and cooling), a practice that drives up engineering, equipment and construction costs, often ruining combined heat and power economics, particularly in small and medium-sized applications (specifically, those less than 1 megawatt). Also, customized combined heat and power systems have greater performance, reliability and warranty risks relative to standardized systems.

The primary activities of the Pacific Region Combined Heat and Power Application Center have been to perform "Level 2" site feasibility assessments,[1] operate combined heat and power workshops and present combined heat and power information at conferences, operate an extensive website (http://www.chpcenterpr.org), produce combined heat and power baseline assessment/action plan reports for each state in the region, and produce combined heat and power system fact sheets for various installations. The specific activities to date are briefly summarized below.

Key accomplishments include a website that has recently been receiving approximately 150 visits per day; completing 13 combined heat and power site feasibility studies; completing 15 combined heat and power case studies; completing combined heat and power state baseline assessment and action plan reports for each of the three Pacific Region Combined Heat and Power Application Center states of California, Nevada, and Hawaii; sponsorship or co-sponsorship of 11 conferences; workshops with more than 600 attendees and an estimated 200 potential end users of combined heat and power; and responses to many direct inquiries for

1 "Level 1" site assessments typically involve approximating the site electrical and thermal loads and then using modeling software to get a rough sense of potential project economics. "Level 2" assessments involve a thorough site visit, collection of a full year of utility bills, and a more detailed technical and economic assessment.

project information and assistance from throughout the center's territory. Following a review of these activities, this report presents the organization's financial history and status, and plans for continued operation in a subsequent project phase.

Site Feasibility / Screening Assessment Reports

The Pacific Region Combined Heat and Power Application Center performed 13 "Level 2" site feasibility assessments for promising combined heat and power projects. Nine of the assessments were conducted during the initial phase of Pacific Region Combined Heat and Power Application Center operations, and four were conducted during the most recent phase.

State Baseline Assessment and Action Plan Reports

The Pacific Region Combined Heat and Power Application Center has produced state combined heat and power baseline assessment and action plan reports for the three states in the Pacific region: California, Hawaii, and Nevada. These reports include comments from stakeholders in each state. These reports will be "working documents" that will be periodically revised to reflect new developments in each state, both in terms of the installed base of combined heat and power systems and changing policy and regulatory conditions.

PRAC Website Traffic

Results show a steady increase in traffic reflecting an increased awareness of the Pacific Region Combined Heat and Power Application Center.

Workshops and Conferences

The Pacific Region Combined Heat and Power Application Center has organized and participated in a number of workshops/conferences/short courses.

Project Profiles

The Pacific Region Combined Heat and Power Application Center has completed 15 project "case studies." These are available on the Pacific Region Combined Heat and Power Application Center website and through the comprehensive collection of Region Application Centers project profiles on the Midwest Application Center website.

The Pacific Region Combined Heat and Power Application Center has engaged in a wide array of activities to promote combined heat and power in the Pacific region since its formal launch in 2005. There is an ongoing need to promote combined heat and power in the Pacific region as an energy efficiency, cost containment, and environmental strategy. However, the challenges are significant as important policies are evolving rapidly, and energy prices and air quality regulations provide significant complications to the installation of combined heat and power in the region. The Pacific Region Combined Heat and Power Application Center is addressing these issues and working to provide the best information possible to combined heat and power stakeholders in the Pacific region.

Benefits to California

This project addresses the Public Interest Energy Research Program's goals of enhancing energy efficiency, diversifying electricity supplies by investing in distributed generation and other clean energy technologies, strengthening California's energy infrastructure to provide for reliability, and continuing California's environmental stewardship.

1.0 Introduction

This project presents a summary of the tasks completed by the Pacific Region Combined Heat and Power Application Center (PRAC) through September 30, 2008, and an overview of the tasks planned for a subsequent "Amendment 2" phase of the project.

Since its inception in 2004, and formal launch in late 2005, the PRAC has been engaged in a wide array of combined heat and power (CHP) and other distributed generation and "microgrid" system education and outreach, project screening/support, policy analysis, and regional and national networking activities. Completed and planned future activities are summarized below, following a brief history of the PRAC and a summary of its operational structure.

History of the PRAC

The PRAC was established in 2004 and received funding for initial operations in late 2005. Core PRAC funding originates with the U.S. Department of Energy (U.S. DOE) and is awarded to the PRAC through the California Energy Commission Public Interest Energy Research (PIER) Program through a State Energy Program grant.

The PRAC features a collaborative structure among University of California Berkeley (UC Berkeley), University of California Irvine (UC Irvine), and San Diego State University. Each university provides some unique capabilities and resources to the center. The primary groups involved on the three campuses are the Energy and Resources Group at UC Berkeley, the Advanced Power and Energy Program at UC Irvine, and the Industrial Assessment Center at Sand Diego State University. The PRAC is led by three co-directors (Tim Lipman, UC Berkeley; Vince McDonell, UC Irvine; Asfaw Beyene, San Diego State University) and three additional principal/key investigators (Dan Kammen, UC Berkeley; Scott Samuelsen and Richard Hack, UC Irvine).

The PRAC has established strategic alliances with key partners in the region. These include three groups that work closely with each "node" of the center -- the Lawrence Berkeley National Laboratory, Sempra Energy, and the California Center for Sustainable Energy (formerly known as the San Diego Regional Energy Office) – and various other groups that are involved less directly. These additional groups work collaboratively with the PRAC to leverage activities and expand the effectiveness of the center's operations.

The PRAC currently has an advisory board of nine CHP experts in the Pacific Region. The current members of the advisory board are:

David Berokoff, Sempra Energy Utilities
Kevin Best, Real Energy
Keith Davidson, DE Solutions, Inc.

Chris Marnay, Lawrence Berkeley National Laboratory
Mark Rawson, Sacramento Municipal Utility District
Charlie Senning, The Gas Company
Irene Stillings, California Center for Sustainable Energy
Eric Wong, Cummins Corp.
Keith Yoshida, The Gas Company

Current CHP systems involve the custom integration of disparate pieces (prime mover, generator, controls, heat recovery, and cooling), a practice that drives up engineering, equipment and construction costs, often ruining CHP economics, particularly in small and medium-sized applications (specifically, those less than 1 Megawatt). Also, customized CHP systems have greater performance, reliability and warranty risks relative to standardized systems.

2.0 Accomplishments

Summary of PRAC Accomplishments Under Grant FED-03-015

The primary activities of the PRAC have been to perform "level 2" site feasibility assessments,[2] operate CHP workshops and present CHP information at conferences, operate an extensive website (http://www.chpcenterpr.org), produce CHP baseline assessment/action plan reports for each state in the region, and produce CHP system fact sheets for various installations. The specific activities to date are briefly summarized below.

- ***Site Feasibility / Screening Assessment Reports***

The PRAC performed thirteen "level 2" site feasibility assessments for promising CHP projects. Nine of the assessments were conducted during the initial phase of PRAC operations, and four were conducted during the most recent phase.

Table 1. Status of Assessments

Site	Assessment	CHP Recommended?	Project Moving Forward?
CA UC campus	Complete	Yes	Pending
Hawaii hotel #1	Complete	Yes	Pending
Hawaii hotel #2	Complete	Yes	Pending
CA ethanol plant	Complete	Yes	Pending
CA bakery	Complete	Yes	Pending
CA Contra Costa Cty. building	Complete	Yes	Pending
CA Contra Costa Cty. building	Complete	No	None
CA laboratory	Complete	Yes	Pending
CA manuf. facility	Complete	Yes	Pending
NV casino	Complete	Yes	Pending
CA lubricant facility	Complete	Yes	Pending
CA wastewater treatment plant	Complete	Yes	Pending
Hawaii hotel #3	Complete	Yes	Pending

These assessments have included a range of potential applications throughout the Pacific region. Table 1 summarizes the status of these assessments. The total amount of CHP that may be installed as the ultimate result of these efforts is unknown at this time, as each assessment typically includes recommendations for more than one system size that may be considered and the clients are in general still considering their options. However, these assessments have

2 "Level 1" site assessments typically involve approximating the site electrical and thermal loads and then using modeling software to get a rough sense of potential project economics. "Level 2" assessments involve a thorough site visit, collection of a full year of utility bills, and a more detailed technical and economic assessment.

included more than 50 MW of total peak demand at the various sites, so this would be an upper limit on the total CHP system capacity that may ultimately be installed.

In addition to these 13 formal feasibility studies, the PRAC has also provided informal project assistance in response to telephone inquiries, and also through information disseminated through the website. These activities have included informational support for a potential project at a poultry farm in Petaluma, California; a wastewater treatment plant in Bakersfield, California; a "transit village" development in Pleasant Hill, California; and a new casino near Reno, Nevada. Efforts are now underway to understand the current status of these potential projects. The PRAC can be of assistance in providing additional information or contacts.

Key Performance Metric: 13 project screenings and reports have been completed

- ***State Baseline Assessment and Action Plan Reports***

The PRAC produced state CHP baseline assessment and action plan reports for the three states in the Pacific region: California, Hawaii, and Nevada. These reports include comments from stakeholders in each state. These reports will be "working documents" that will be periodically revised to reflect new developments in each state, both in terms of the installed base of CHP systems and changing policy and regulatory conditions.

Key Performance Metric: 3 state baseline assessment action plan reports (one for each state in the region) along with annual updates

- ***PRAC Website Traffic***

Figure 1 shows the hits per month for the PRAC website (http://www.chpcenterpr.org) since its launch in November 2003. Only hits external to the local domain (i.e., UC Irvine 128.200.X.X) are included, which means the hits indicated are not produced by PRAC web developers. From August 2004 to January 2005, a file server failed, resulting in lost logs for that period of time. However, the regression line suggests typical trends in that timeframe. The results show a steady increase in traffic reflecting an increased awareness of the PRAC. The large spike around February/March 2006 is associated with a workshop held on February 14-16, 2006. Another large spike is observed in September 2006 associated with a workshop held on September 19, 2006. Also, in late 2006, a number of case studies and additional information were posted on the site for download. Workshop proceedings from the May 2008 CHP workshop were made available in June and July of 2008.

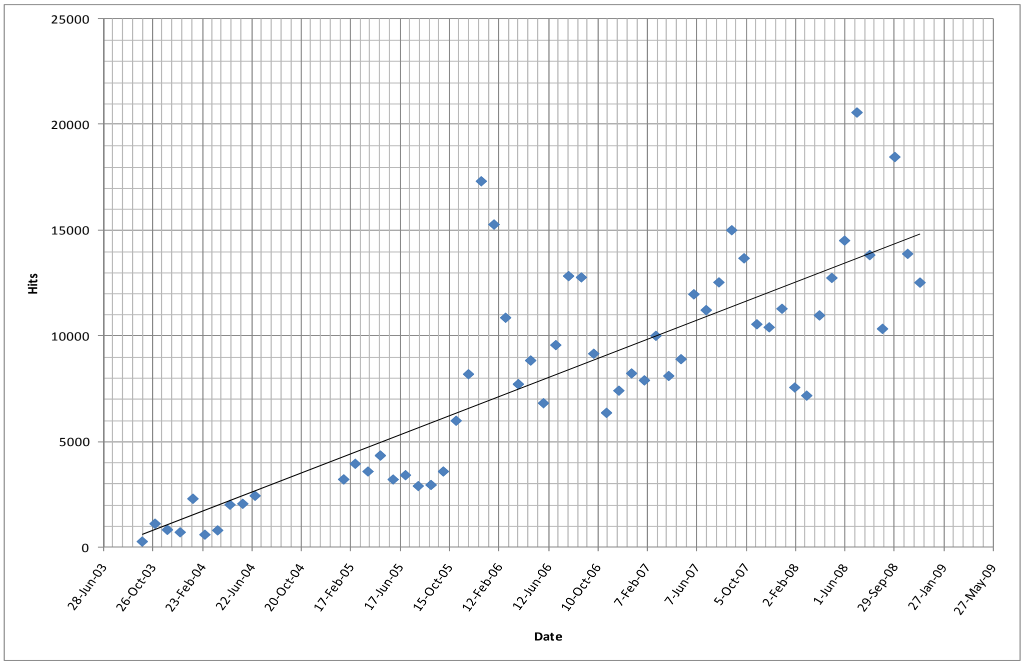


Figure 1: Website Hits Per Month

Figure 2 shows the website traffic information in terms of visitors. For purpose of this analysis, a visit is considered a unique hit in which the visitor remains connected to the site for at least 15 minutes. Only hits external to the local domain (i.e., UC Irvine) are included which means these hits are not produced by site developers.

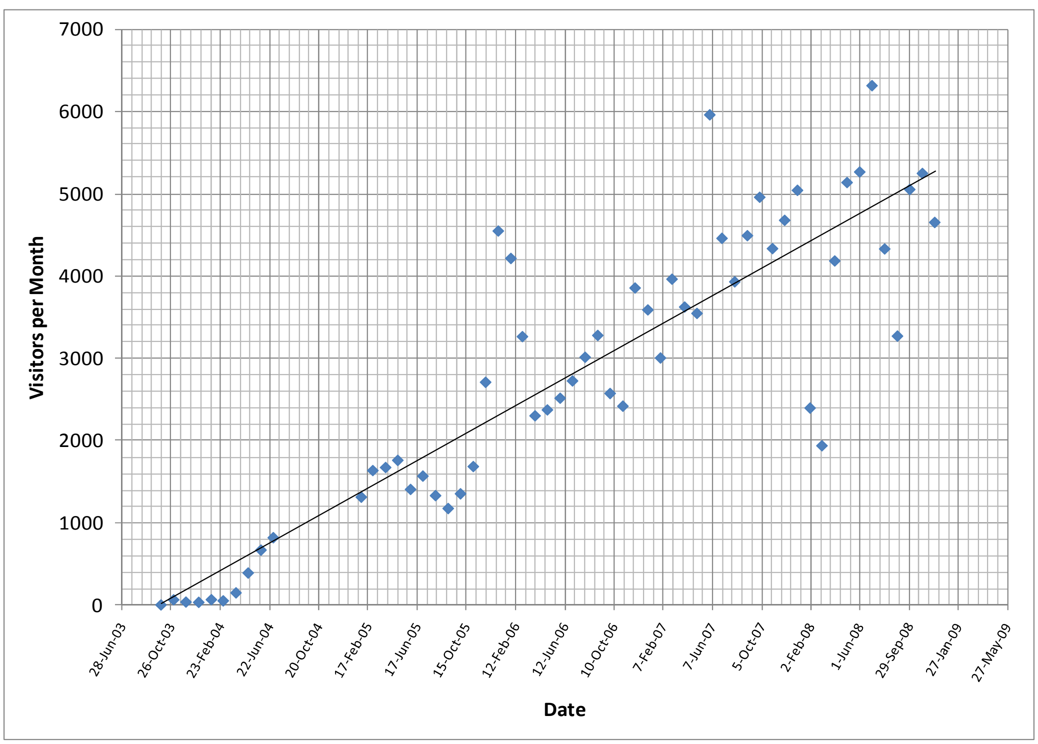


Figure 2: Visitors Per Month

Figure 3 shows the website traffic information in terms of data downloaded. This would include fact sheets, state energy plans, and other workshop presentations. Note that this data has been available only since April 2007.

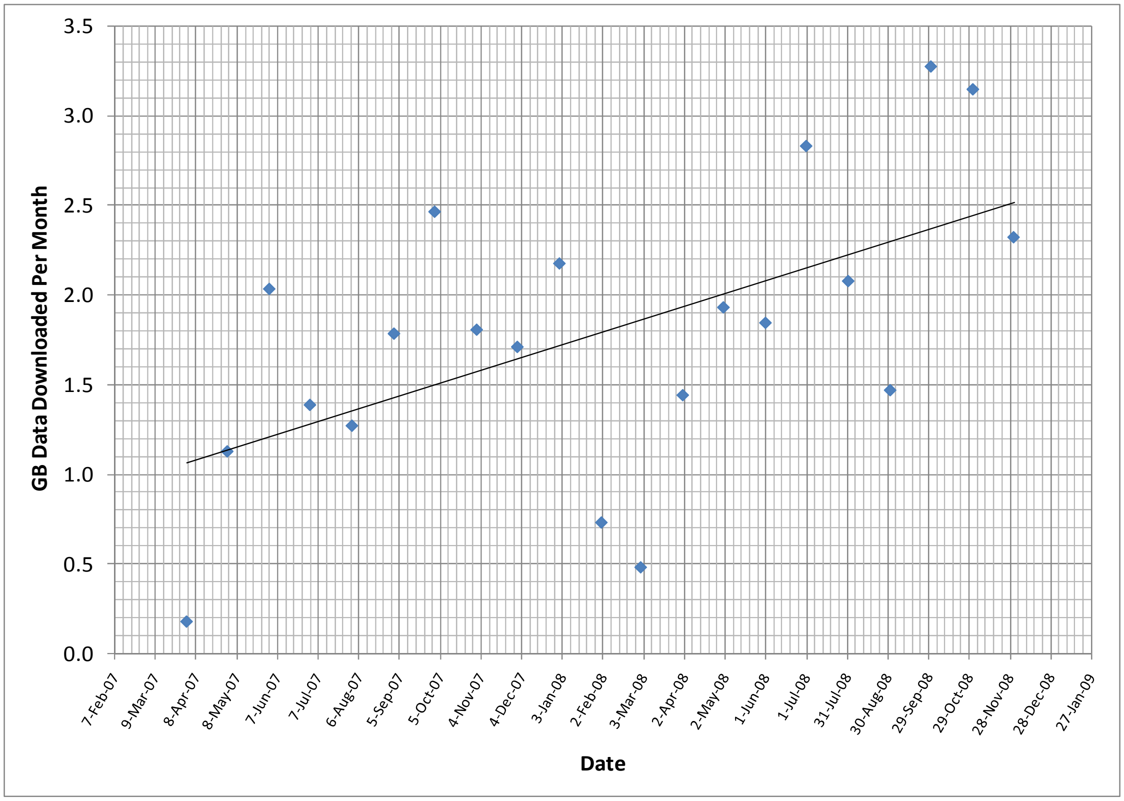


Figure 3: Gigabytes (GB) Downloaded from Site Per Month

In early 2008, UC Irvine began using a different website traffic monitor (Google Analytics—www.google.com/analytics), which was felt to provide a more supportable and reliable capability. This service is free and collects data externally. However, for consistency, the previous web traffic monitoring strategy (Alterwind) was utilized for the figures shown here.

Key Performance Metric: Website "visitors" (not just hits) per month steadily increasing and now about 150 per day

- ***Workshops and Conferences***

The PRAC has organized and participated in a number of workshops/conferences/shortcourses. The events that were principally organized and run by PRAC include:

Waste Heat to Power Workshop—March 2005, Irvine California
A workshop dedicated to advancing the use of waste heat as a general resource for production of electricity. 61 attendees. In conjunction with North West Region Application Center.

Clean Fuels for California and the West—January 2006, Napa, California
A workshop directed at use of renewable fuels generated by waste water treatment and agricultural applications. ~120 attendees. In conjunction with RealEnergy.

Waste Heat to Power II—February 2006, Irvine California
A workshop dedicated to advancing the use of waste heat as a general resource for production of electricity. 80 attendees. In conjunction with North West Region Application Center.

Clean Fuels for California and the West—September 2006, Newport Beach, California
A workshop directed at use of CHP for university sectors as well as applications using waste fuels generated by wastewater treatment and agricultural applications. 87 attendees.

Introduction to Distributed Energy for Southern California Edison Engineers—November 2006, Irvine California
A short course introducing Southern California Edison engineers to distributed generation and how it can compliment/benefit the grid. The course included a tour of 3 local sites with installed/operating distributed generation, including reciprocating engines, microturbines, and fuel cells. 12 attendees.

California BioEnergy Workshop—April 2007, Napa California
A workshop directed at use of biofuels generated by dairy and food processing industries. Special focus on identifying policy and regulatory pathways to enable future growth. 165 attendees including approximately 35 end-users. In conjunction with RealEnergy.

Ingersoll Rand "Power Lunch"—April 2007, San Leandro California
A workshop to introduce end-users to the concept to CHP and the capabilities of Ingersoll Rand. 35 attendees, nearly all end-users. In conjunction with Ingersoll Rand.

Waste Heat to Power III—September 2007, Houston, Texas
A workshop dedicated to advancing the use of waste heat as a general resource for production of electricity. 95 attendees. In conjunction with NW RAC and Gulf Coast Region Application Center.

"CHP 101" Session for Energy Sustainability Training—March 2008, White Plains, New York
Energy sustainability training for Fortune 500 company managers, including a CHP session presented by the PRAC and organized jointly with The Conference Board. Approximately 30 attendees, with 20-25 potential end-users (representing large companies such as Rockwell International, Hitachi, and the US Postal Service).

Efficient CHP Technologies for Industry—May 2008, Downey, California
A workshop dedicated to advancing the use of waste heat as a general resource for production of electricity. 69 attendees. In conjunction with Sempra.

Additionally, PRAC regularly participates in the California Alliance for Distributed Energy Resources conference by organizing sessions and delivering updates on PRAC activities, and also has presented on PRAC activities at meetings of Rebuild Hawaii, the California Water Engineers Association, and the UC system energy managers annual conference.
Key Performance Metric: PRAC has sponsored or co-sponsored 11 CHP workshops and conferences, with a total of over 600 attendees and an estimated 200 "end-users," along with additional outreach activities at other meetings and conferences that have provided direct outreach to hundreds more potential CHP adopters

- ***Project Profiles***

The PRAC has completed 15 project "case study" profiles. These are available on the PRAC website, and also through the comprehensive collection of Region Application Centers project profiles on the Midwest Application Center website.

The case studies are for the following applications and prime mover types:

- Hotel microturbine
- Brewery fuel cell
- Wastewater treatment microturbine
- Casino reciprocating engine
- Office building microturbine
- Office building reciprocating engine
- Pharmaceutical laboratory reciprocating engine
- Dairy reciprocating engine
- Winery microturbine
- Correctional Facility fuel cell
- University campus #1 with gas and steam turbine
- Data center with microturbine
- Large office building with reciprocating engine
- Mixed-use development with office/lab/retail and microturbine
- University campus #2 with gas and steam turbine

Key Performance Metric: PRAC has produced 15 project profiles for a wide variety of applications and CHP system types in the Pacific region

Summary of Submitted PRAC Grant Deliverables Through September 30, 2008

- CHP Project profiles (14 individual project profile fact sheets 2007/2008) – **Attachment 1-14**
- California CHP Baseline Assessment/Action Plan Report (2007; updated 2008) – **Attachment 15 (2008)**
- Hawaii CHP Baseline Assessment/Action Plan Report (2007; updated 2008) – **Attachment 16 (2008)**
- Nevada CHP Baseline Assessment/Action Plan Report (2007; updated 2008) – **Attachment 17 (2008)**
- CHP Project Feasibility Study Reports (13 individual reports 2007/2008)
- Comprehensive CHP Project Profile Report (updated)
- CHP Premium Power Assessment report (2008) –

  Attachment 18
- Targeted CHP Outreach Materials (2007/2008)
- Virtual Meeting Center Report (2008)
- CHP Outreach Materials Report (2008)
- PRAC Sustainability Plan Report (2007)

Project Plan for Grant Amendment 2

The PRAC "Amendment 2" grant includes proposed project tasks from the Special Energy Program proposal submitted for Fiscal Year 2007. The project performance period for this grant amendment is through December 31, 2008. At present, the ability of the PRAC to complete the scope of work for Amendment 2 is in question due to the potential ability of the California Energy Commission to administer the project for the U.S. DOE, and for the requisite funding to be made available. The project team would therefore require a no-cost extension to complete this set of tasks, if and when an agreement can be reached with the Energy Commission and/or U.S. DOE for these activities to be performed.

The proposed tasks for Amendment 2 are summarized as follows.

FY 2007 Grant Extension Tasks

Task 1: Targeted Workshop
This task will allow the PRAC to conduct an additional targeted CHP market workshop in 2008, beyond those already planned.

Task 2: Targeted Market Participation
This funding would support a presence of PRAC at key CHP oriented conferences (e.g., PowerGen 2008).

Task 3: CHP System Field Operational Performance Assessment
This task would consist of systematically examining several CHP systems in operation in the Pacific region and assessing their performance. Performance metrics would be gathered with regard to electrical and overall thermal operating efficiency, operating "duty cycle" patterns, maintenance needs and downtime/availability, and other relevant performance related issues.

Task 4: Project Screenings For High Impact Projects In Target Markets
Under this task San Diego State University and the Industrial Assessment Center would lead the effort to conduct 4-5 additional project feasibility screening studies, in target markets identified through the state CHP action plan and workshop/road mapping activities.

Task 5: Project Profiles For CHP Target Markets
Under this task, the PRAC would produce 4-5 additional project profile studies targeted at attractive applications and niches for CHP in the Pacific region.

Task 6: Revised State Baseline And Action Plan Reports
Under this task, the PRAC would perform a major round of revisions and additions to the individual state baseline assessment/action plan reports for California, Hawaii, and Nevada.

Task 7: Ongoing Project Management
Under this task, the three universities will continue to work with the Energy Commission on coordination of PRAC network activities with other complementary state energy office and regional efforts.

PRAC Funding History

The PRAC was initially funded with a $300,000 grant from the U.S. DOE in FY 2003. Since then, as shown in the figure below, U.S. DOE funding has declined significantly due to reductions in its budget for distributed energy research.

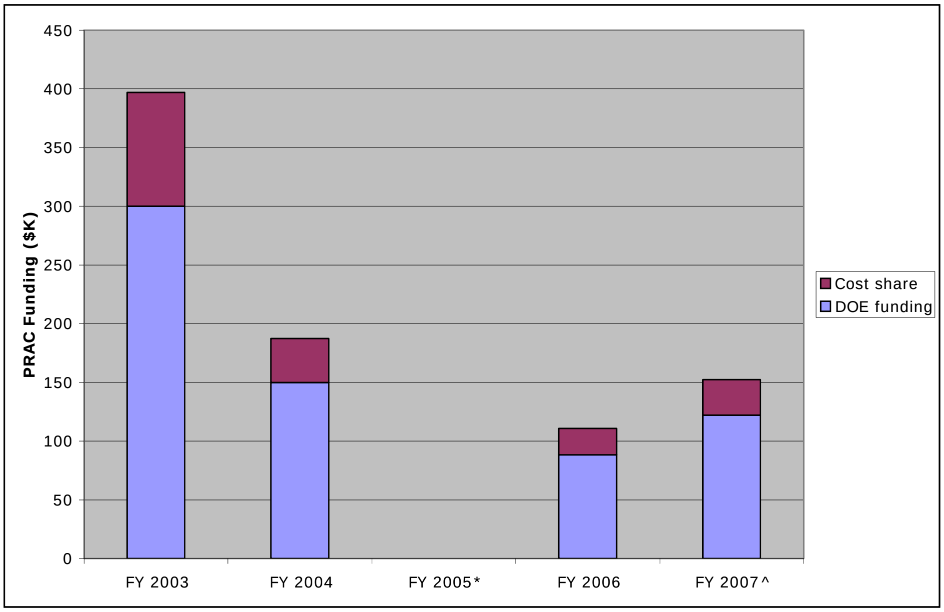


Figure 4: Summary of Total Funding Received or Programmed for the PRAC

Notes:
* The PRAC did not request U.S. DOE funding in 2005 due to delays in the administration of the Fiscal Years 2003 and 2004 grants. Also in 2008, $25K was offered to the PRAC but these funds were not pursued due to the administrative burden involved.
^ The Fiscal Year 2007 funding shown has recently been programmed, but not yet formally requested. The cost share contribution shown is the minimum amount required by the grant terms and conditions.

The above figure also shows the total funding received by the PRAC including cost share contributions. Cost share contributions have been provided by the California Air Resources Board, the California Energy Commission, the Bay Area Air Quality Management District, Sempra Energy Utilities, and the universities themselves.

Conclusion

The PRAC has engaged in a wide array of activities to promote CHP in the Pacific region since its formal launch in 2005. There is an ongoing need to promote CHP in the Pacific region as an energy efficiency, cost containment, and environmental strategy. However, the challenges are significant as important policies are evolving rapidly, and energy prices and air quality regulations provide significant complications to the installation of CHP in the region. The PRAC is addressing these issues and working to provide the best information possible to CHP stakeholders in the Pacific region.

East Bay Municipal Utility District

600 kW microturbine CHP/chiller system

PACIFIC REGION CHP APPLICATION CENTER

Project Profile

combined heat & power in an administration building

Quick Facts

Location:
Oakland, California

Capacity:
600 kW (ten Capstone C60 microturbines)

Fuel: Natural gas

Noise Level: 70dB at 30 feet

Planning and Construction Time:
23 months

System Online: July 2003

Total Project Cost:
$2,510,000 (administration building only)

Energy Cost Savings:
$200,000 – $300,000/year

Expected Payback Time:
6 to 8 years (with SGIP rebate)

Maximum On-Site Plant Efficiency with Heat Utilization: 74%

Funding Sources:
California Public Utilities Commission/Pacific Gas & Electric
California Energy Commission

Project Overview

The East Bay Municipal Utility District (EBMUD) is a publicly owned utility that provides water service to portions of two counties in the San Francisco Bay Area. Its water supply system covers 325 square miles (841 km^2) and serves some 1.3 million customers. One of EBMUD's largest electrical demands is its own headquarters. In 2001 EBMUD decided to install a distributed generation (DG) system at its downtown Oakland administration building.

The motivation for the project was to reduce energy costs and ultimately increase reliability while the electric utility industry experienced financial and technical turbulence.

The DG system consists of ten 60-kW Capstone microturbines and a ~180 refrigeration ton (RT) (~633-kW) York absorption chiller. EBMUD has also installed two 60-kW microturbines at its Adeline Maintenance Center, along with a 30 kW solar PV system. The selection of microturbines was driven by the air quality restrictions in downtown Oakland.

Fuel cells were also considered. Apart from their higher capital costs they were rejected because they proved to be too heavy for the roof.

It is estimated that the DER system will produce enough residual heat to power the adsorption chiller to meet 60% of the existing cooling load that is currently met by two 880-kW (250 RT) centrifugal chillers.

Costs & Financial Incentives for the Administration Building

- System design: $125,000
- 10 Capstone microturbines: $1,100,000
- Installation of turbines: $410,000
- Absorption chiller: $360,000
- Electrical and gas connections: $130,000
- Service contract: $100,000
- Air permit: $30,000
- Other costs: $255,000

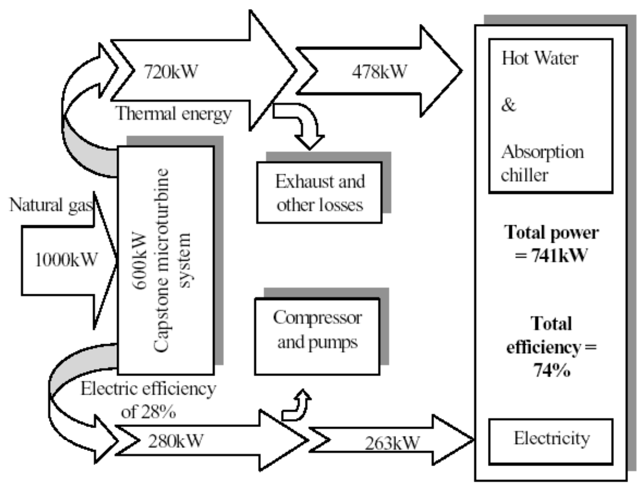
Total cost: $2,510,000

To assist with project costs EBMUD has received a $2,000,000 low interest (3%) loan (payable within 11 years) from the California Energy Commission (CEC) and a $900,000 rebate from the California Public Utilities Commission (CPUC) and Pacific Gas and Electric Co. (PG&E) under California's Self-Generation program (SGIP).

A main reason for the installation of micro-turbines is their small footprint and weight. Each turbine is placed in a space only 30 in. (76 cm) wide and 77 in. (196 cm) long.

Natural gas compressors located on the roof of the EBMUD admin. building.

Maximum On-Site Plant Efficiency



The efficiency of serving the entire heating and cooling loads was critical to obtaining the required 42.5% overall FERC energy efficiency rating. This energy efficiency level is necessary to receive state funding as part of the California Public Utilities Commission SGIP program. EBMUD operates the individual microturbines only when there is sufficient heating or cooling load to meet this level of efficiency on an annual basis.

The microturbines will occasionally be shut down if there is insufficient thermal load, regardless of electrical load requirements.

EBMUD does not sell electricity back to the grid. Under agreement with the local utility it uses the system for onsite cogeneration only.

The system operation is controlled by waste heat needs and not by electrical demand. It is designed to first meet the building thermal load and then to contribute to electricity supply.

The system produces NO_X emissions of 0.2lb/MWh_{elec}. This is roughly 7% of the NO_X emissions released by conventional US electricity production.

Further information can be found at

EBMUD: www.ebmud.com
Microturbines: www.capstoneturbine.com
Self-Generation Incentive program (SGIP): www.pge.com/suppliers_purchasing/new_generator/incentive/index.html
PRAC: www.chpcenterpr.org

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Contact Information

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Email: telipman@berkeley.edu

PACIFIC REGION CHP APPLICATION CENTER

combined heat & power in a pharmaceutical research facility

Johnson & Johnson

2.2 MW reciprocating CHP system

Project Profile

Quick Facts

Location:
La Jolla (near San Diego), CA

Capacity:
2.2MW (two 1,100 kWe 16-cylinder reciprocating engines from Cummins)

Fuel: Natural gas

CHP system:
Hot water and absorption cooling

Grid Interconnection:
The system can be operated in grid-independent mode to provide high-reliability power

System Online:
March 2004

Total Project Cost:
Approximately $4,000,000

Energy Cost Savings:
Approximately $1,000,000/year

Estimated Payback Time:
4 to 5 years

Funding Sources:
Johnson & Johnson, San Diego Regional Energy Office (SDREO) refund of $800,000 (from the CA Self-Generation Incentive Program)

Project Overview

Johnson & Johnson Pharmaceutical Research & Development (J&JPRD) operates eleven research laboratories worldwide and is a leading maker of personal care products, diabetes medications, and other pharmaceuticals. Three years ago J&JPRD planned to double the size of its La Jolla, California facility space from 120,000 sq. ft. (11,000 m^2) to 300,000 sq. ft. (28,000 m^2).

This project was conceived in 2003, when the California energy crisis made J&JPRD reluctant to sign long term electricity contracts. J&JPRD sought to find an integrated, holistic approach to its energy needs

For the research facility in La Jolla electrical loads are high during the business hours of 7am to 6pm (the maximum peak load is around 2.5 GW), when power peak rates in California also climb. These circumstances make the facility an ideal absorption chiller candidate. Almost all recovered heat can be utilized by the cooling system. However, because there also are cold days at this seaside location J&JPRD has to heat the facility during some periods and the need for recovered heat is well distributed over the whole year.

Originally, fuel cells and microturbines were also considered, but were rejected for reasons including better maintenance agreements for reciprocating engines and a smaller system footprint. The installed 2,200 kW internal combustion system produces around 15,000,000 KWh/yr of electricity plus 10,548,040 kWh/yr (= 360,000 therms) of heat and 1,120,000 kWh/yr (= 1,600,000 ton-hr/yr) of chilled water, providing more than 90% of the facility's electric power and much of its heating and cooling needs. The current overall exhaust heat utilization is about 75%.

The installation was done in two phases. Unit one, which is powering the old J&JPRD building, came online 2003 and unit two was switched on in February 2004.

As part of the agreement for this project, J&JPRD is required to buy 5% of its electricity needs from the grid (San Diego Gas & Electric). Furthermore, to obtain the permit, J&JPRD had to demonstrate that the system does not back-feed electricity to the grid.

It is estimated that the CHP system at J&JPRD saves around 3,200,000 lb (1,450 tonnes) CO_2/yr. This is equivalent to the operation of about 285 automobiles.

Picture by Johnson&Johnson

Left hand side: 500 RT (refrigeration ton) absorption chiller.

Picture below: 16-cylinder 1,100 kW reciprocating engine from Cummins.

Picture by Johnson&Johnson

The system runs without any operator and is fully monitored by DSL connection. Sensors automatically page and dispatch a technician when needed.

Costs & Financial Incentives

The total costs of the CHP project are estimated at $4,000,000. It is difficult to exactly determine the total project cost because a complete new building with HVAC system was erected and some of the CHP and HVAC components are not clearly dissoluble. Some of the HVAC aspects were rolled into the larger construction budget and new elements were married up to existing elements. However to mitigate the high costs J&JPRD received a $800,000 rebate from the San Diego Regional Energy Office (SDREO) under the Self-Generation Incentive Program.

SDREO is an independent, public-benefit, non-profit corporation that provides objective information, research, analysis and long-term planning on energy issues for the San Diego region.

IC engines and large gas turbines (with waste heat utilization)	Incentives ($/W)
with renewable fuel	1.00
with non-renewable fuel	0.60

Incentives from the Self-Generation program for qualifying equipment for the year 2006 are shown in the table on the left hand side.

Future Tasks

At the La Jolla site five heat exchangers are currently in place. There is enough waste heat for a sixth heat exchanger, which is planned to be added to maximize heat utilization. When this sixth heat exchanger comes online, two old remaining boilers can be decommissioned and this will result in an overall exhaust heat utilization of nearly 100%. Furthermore, J&JPRD is exploring the possibility of adding a 200 kW photovoltaic system for additional peak power shaving. Moreover, other Johnson & Johnson sites are possible CHP candidates. Plans are being discussed to install a CHP system at an East Coast location, as well as at a Puerto Rico site.

Further information can be found at

Johnson & Johnson (La Jolla):
www.jnjpharmarnd.com/locations/ca.html

Self-Generation Incentive Program:
http://www.sdenergy.org/ContentPage.asp?ContentID=35&SectionID=24

PRAC: www.chpcenterpr.org

Version 1.2 12/19/06

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"There are so many benefits to cogeneration. Innovation is at the core of our R&D efforts, and so we're pleased to be using this cutting-edge cogeneration technology to power, heat and cool our new laboratories."

J&JPRD Senior Vice President of Drug Discovery, Michael Jackson

"Self-generation reduces electricity consumption from the grid, reduces the need for new infrastructure and helps the environment. This project is great for the San Diego region."

SDREO Executive Director, Irene M. Stillings

Joseph Gallo Farms Dairy

700 kW reciprocating CHP system

PACIFIC REGION CHP APPLICATION CENTER

Project Profile

combined heat & power in a dairy

Quick Facts

Location: Atwater, CA

Capacity: 300 kW Caterpillar 3412 and 400 kW Caterpillar G399 reciprocating engine generators

Fuel: Digester gas (methane)

CHP system:
Process steam for cheese making

Construction Time: 25 months

System Online:
October 2004, upgrade from 300 kW to 700 kW in February 2006

Total Project Cost:
$3,200,000 (including the 400 kW upgrade in February 2006)

Energy Cost Savings:
$800,000/year (electricity and propane)

Expected Payback Time: 3 to 4 years (without incentives)

Funding Sources:
Joseph Gallo Farms;
California Dairy Power Production Program (DPPP);
CA Self-Generation Incentive Program

Project Overview

Joseph Gallo Farms, founded in 1979, accommodates 16,000 dairy cows across five dairies in Merced Country. About 5,000 of them are at the Cottonwood Dairy. Each cow produces about 120 lbs (54 kg) of liquid and solid waste per day, which can result in serious environmental problems. Authorities are struggling with the air and water pollution consequences and are searching for solutions. One can be the installation of an anaerobic digester to produce biogas from manure and allow electricity generation. In 2004 a 44,225,000 gallon (167,400 m^3) lagoon digester with 7 acre surface area (28,000 m^2) in combination with a 300-kW Caterpillar 3412 reciprocating engine were installed at the Cottonwood site.

The digester produces up to 300,000 cubic feet/day (8,500 m^3/d), but only 130,000 cubic feet/day (3,700 m^3/d) are used by the 300-kW Caterpillar engine. To avoid flaring or releasing the remaining fuel to the atmosphere, Josephs Gallo Farms installed a second, 400-kW reciprocating engine in February 2006. With these two engines the system produces 5.6 GWh electricity onsite every year. Furthermore, the Cottonwood dairy also houses a cheese plant which processes around 900,000 lbs (408,000 kg) milk per day. Methane production is accelerated by the addition of warm plant clean up water to the digester.

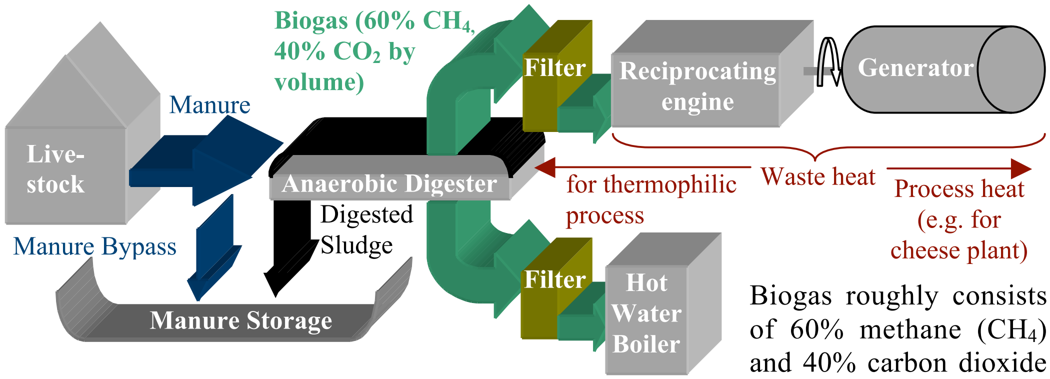
The new 700-kW CHP system, which also uses waste heat for the cheese plant, can offset 55% of the utility-provided electricity (the peak load of the dairy is around 1.6 MW). The exhaust waste heat is used to produce steam for pasteurizing and sterilizing. Additionally, heat from the engine jacket coolant may be used in the future to preheat air for a whey drier.

The dairy operates the entire digester system on its own at a maintenance cost of roughly $150,000 per year. This includes H_2S scrubber materials replacement, weekly electrical equipment and pump motor checks, as well as major engine overhauls every 16,000 hours. Furthermore, the dairy has to change the engine oil every 500 hours and has to perform engine tune ups every 1,000 hours.

Costs & Financial Incentives

Originally, the total project cost was projected at $1,290,000. However, because of higher than expected costs for the manure collection, manure separation, and gas treatment systems, and for the grid interconnection, the final project costs were $2,700,000 (without the 400 kW upgrade). To mitigate these costs the farm received a buy-down grant of $600,000 from the California Dairy Power Production Program (DPPP) as well as $238,000 from the CA Self-Generation Incentive Program. Joseph Gallo Farms has also applied for a $400,000 grant for the new 400 kW engine. The purpose of the DPPP program was to stimulate the installation of biologically-based anaerobic digesters for gasification and biogas electricity generation. This program – which expired in March 2004 – contained two types of grants: a) an investment subsidy, which covered up to 50% of the system capital costs, and b) a production incentive of 5.7 cents per kWh of electricity produced.

Schematic of an anaerobic digester system (e.g. dairy)



Biogas roughly consists of 60% methane (CH_4) and 40% carbon dioxide ($C0_2$) and is produced by bacteria in the absence of oxygen in a covered, impermeable anaerobic digester. Almost any organic material can be processed in this manner, e.g. leftover food, waste paper, grass, etc. Two major processes are available: a) *mesophilic*, which takes place at ambient temperatures between 68°F (20°C) and 104°F (40°C) and b) *accelerated thermophilic*, which needs waste heat to increase the process heat up to 158°F (70°C). With such an anaerobic digester, a lactating dairy cow can generate enough biogas to generate approximately 2.5 kWh electricity every day. However, very important for a well-functioning system is the H_2S scrubber (filter). This reduces the corrosive hydrogen sulfide content in the biogas, which would otherwise reduce the engine lifetime.

Picture above: 400 kW reciprocating engine

Picture below: the 7 acre digester cover

Further information can be found at

Joseph Gallo Farms: http://www.josephfarms.com/
DPPP: http://www.wurdco.com/index.htm
Self-Generation Incentive Program: www.pge.com/suppliers_purchasing/new_generator/incentive/index.html
Methane (Biogas) from Anaerobic Digesters: http://web.archive.org/web/20041124201613/www.eere.energy.gov/consumerinfo/factsheets/ab5.html?print
PRAC: www.chpcenterpr.org Version 1.3 4/17/07

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Unlike traditional lagoons that emit methane directly into the atmosphere, digesters capture these emissions. This is very important because of the high methane content of the released gas. Methane is about 20 times more potent as a greenhouse gas than $C0_2$.

“Steep construction and maintenance costs with bureaucratic hurdles and conflicts with utility providers have prevented many interested dairies from building biogas operations”
Mike Marsh, Chief Executive Officer of Modesto-based Western United Dairymen.

PACIFIC REGION CHP APPLICATION CENTER

Network Appliance Data Center

1.1 MW CCHP System

Project Profile

combined cooling heat & power in a data center

Quick Facts

Location: Sunnyvale, California

Capacity: 1.125 MW

Three Hess Microgen 375-kW reciprocating engine systems

System Online: 2004

Fuel: Natural gas

Chiller: 318 tons

Three Nishiyodo 106-ton silica-water gel adsorption chillers

Chiller Coeff. of Performance: 0.7

Power Demand: 60% of electricity for servers, and 40% for cooling

State Rebate: $1 million

Funding Sources:

California Public Utilities Commission – Self-Generation Incentive Program

Cooling a Datacenter

In a climate as variable as Sunnyvale, where summer daytime heat is often paired with coolness in the evening, intelligent design of the cooling system can drastically reduce the electrical demand. This building has managed to keep cooling to approx. 40% of the overall power consumption by effective use of an outside air economizer and the supplementary chilling provided by the adsorption units. If the temperature outside is below 65°F, the economizer brings in outside air. This is enough to cool the facility for a third of the year. For the remaining two-thirds of the year when the facility needs supplemental cooling, the adsorption chillers and two 250-ton R134A electrical compression chillers assist in ensuring the data servers remain fresh and cool.

Project Overview

Founded in 1992, NetApp is a global storage and data management provider headquartered in Silicon Valley, at 495 East Java Dr., in Sunnyvale.

NetApp began successful operation of their first combined cooling heat and power (CCHP) system at their headquarters in 2001. With several years of success with CCHP under their belt, NetApp contracted Air Systems to install another system for their new data center. This system came online in 2004.

One significant difference between the two systems is the cooling. Whereas the first NetApp CCHP system uses a conventional lithium-bromine (LiBr) a**b**sorption chiller powered by the generator's waste heat, the new data center uses an innovative water a**d**sorption system.

The data center has a peak electrical load of about 800kW and houses 6638 sq. ft. of server space dedicated to NetApp's internal data management needs. Designed so that electrical base load demand could be entirely met by the Hess Microgen reciprocating engine CHP units, the system is now mainly operated in "peak shaving" mode. Base load operation is no longer economical with the recent increased cost of natural gas, although using less electric power during peak times still enables the company to buy power at a lower rate.

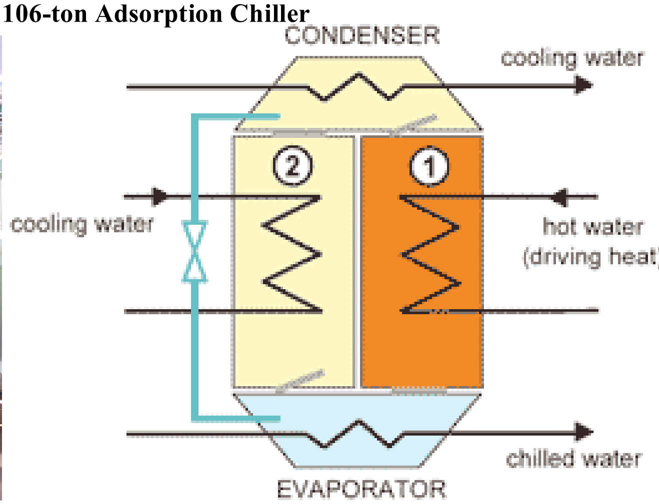
3 x 375 kW Hess Microgen CHP units

Adsorption Chillers

With such a large cooling demand, and potentially low temperature differentials between the chilled water and the exhaust water, adsorption chillers are a natural fit for a data center, typically performing at a COP between 0.5 and 0.7. In this CCHP installation, the exhaust from the engine generator units heats the water that is used to drive an adsorption cycle. The adsorption Nishiyodo chillers operate continuously in this cycle:

(a) In chamber 2 Silica-gel desiccants chill water from approximate 85°F down to 45°F by adsorbing water vapor from the evaporator.
(b) In chamber 1, the heated water from the engine waste heat drives the water out from the sorbent material, effectively regenerating its capacity to adsorb.
(c) The released water vapor now condenses and flows back into the evaporator.
(d) When the sorbent in the chamber 2 saturated with water, the evaporator switches to chamber 1 to continue the chilling process, and the cycle is repeated.

Nishiyodo 106-ton Adsorption Chiller



Further information can be found at

NetApp:
http://www.netapp.com/us/

Air Systems, Inc.:
http://www.airsystemsinc.com/

PRAC: http://www.chpcenterpr.org/

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"The cogeneration system is used on an economic dispatch basis and provides supplemental power and cooing. It is not used for back-up purposes."

- Thom Bryant, NetApp

PACIFIC REGION CHP APPLICATION CENTER

combined heat & power in a Las Vegas casino

Las Vegas Nevada Hotel Casino

4.9 MW reciprocating CHP system

Project Profile

Quick Facts

Location:
Las Vegas, Nevada (Clark County)

Capacity:
4.9 MW (six overhauled 817 kW Caterpillar 3516 reciprocating engines)

Fuel: Natural gas

CHP system: Hot water

Energy Efficiency:
Approx. 75% overall thermal efficiency is expected

Construction Time:
12 months

System Online: May 2004

Total Project Cost:
Approximately $7,500,000

Energy Cost Savings:
Estimated $1,500,000/year

Expected Payback Time:
5 years

Funding Sources:
No incentives from local, state or federal sources. All costs were paid by the casino/hotel.

Project Overview

This Las Vegas, Nevada hotel/casino project is one of the first casino CHP projects to be implemented in the U.S. The project was implemented at one branch of a major hotel chain (who wishes to remain anonymous).

A company-wide analysis for the hotel chain has shown that the group spends almost $60 million a year in gas and electricity across 18 major properties. The company has found that lighting, heating and cooling requirements constitute the vast part of these costs.

This first CHP system operating at a Las Vegas casino, with 4.9 MW of capacity, went online May 1, 2004 after only a year of construction. Four of the six overhauled Caterpillar 3516 natural gas fired reciprocating engines are located at the back of the casino complex. The other two engines are located under the casino’s multi-media sign to provide electricity for the sign.

The CHP system is designed to deliver 180 ^{o}F - 200^{o}F hot water for domestic hot water and for space heating needs during the winter months.

The CHP system is designed to serve the energy needs of the hotel. The convention center was not included due to the sporadic nature of its electricity demand. The total electricity peak demand of the facility is about 11 MW. Although the system could potentially sell power back to the grid, Nevada Power has required the casino to buy at least 200 kW from the grid at all times. The system was set up to run 24 hours a day and serves the base load electrical demand. Approximately 50% of the annual electricity needs are served by the 4.9 MW CHP system, and it is expected to achieve an average overall thermal efficiency of about 75%.

The casino/hotel management considered installing absorption chillers as part of the project, but decided to keep initial costs down and delayed installation of an absorption chiller system. This would have decreased energy bills further but would have added significantly to the initial capital cost of the project, and likely would have extended the project payback time.

Costs & Financial Incentives

The entire project cost of $7,500,000 was covered by the hotel chain. The company received no incentives from local, state, or federal sources. The system economics are affected by the decision to not (at least initially) install an absorption chilling system as this reduced the initial capital cost but also necessitates "dumping" heat during the hot summer months, lowering the overall system efficiency.

Emissions

All six Caterpillar units are equipped with exhaust gas recirculation (EGR) systems to reduce oxides of nitrogen (NO_X) emissions, and tests have measured NO_X emission levels of 1.7ppm. Clark County is in serious non-attainment for PM_{10} (Particular Matter smaller than 10µ meter = 10^{-6} meter) and serious non-attainment for carbon monoxide. Therefore all units must obtain air emissions permits and all new DG sites must meet a 'Best Available Control Technology (BACT)' standard. There are thresholds in place that trigger additional permitting activities if pollutant emissions exceed a 'major threshold.'

The picture on the left shows the exterior of the hotel and casino.

Pictured above: One of the six refurbished Caterpillar reciprocating engines. The engines require an oil change every 1,000 hours and demonstrate an availability of 94% to 98% (on a monthly basis).

The picture to the left shows parts of the 3,500-gallon hot water loop that serves the hotel's hot water needs.

If the "macrogrid" fails, the casino's CHP system and backup generators are able to satisfy the facility's most important electricity, cooling, and hot water demands.

The casino is still functional in such an event.

Further information can be found at

Nevada State Office of Energy: http://energy.state.nv.us
Regulatory Requirements Database for Small Electric Generators (e.g. emissions): http://www.eea-inc.com/rrdb/DGRegProject/index.html
PRAC: www.chpcenterpr.org

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PACIFIC REGION CHP APPLICATION CENTER

combined heat & power in a commercial complex

One Market Plaza

1.5 MW CHP System

Project Profile

Quick Facts

Location: San Francisco, California

Capacity: 1.5 MW (three 500-kW Waukesha VGF L36GSID natural gas-fired engine systems)

System Online: 2003

Fuel: Natural gas

System Efficiency: Estimated 62% overall efficiency

Power Output: 30% of electricity and 85% of steam demand

State Rebate: 30% of capital costs

Expected Payback Time: 5 to 6 years (with incentives)

Funding Sources:
- Equity Office
- California Public Utilities Commission (CPUC)
- Pacific Gas and Electric (PG&E)

Project Overview

One Market Plaza, managed by Equity Office Properties Trust, is located in the financial district of San Francisco, California. Built in 1976, the complex consists of two high-rise towers, a six-story annex, and retail space that total nearly 1.5 million square feet of office space. Following the deregulation of energy markets in California, distributed generation became a viable option for commercial properties. As a result, Equity Office created a subsidiary, On-Site Energy Providers, to install cogeneration systems in their buildings. In addition to reducing demand for electricity from the utility, by using less power during peak times, Equity Office is also able to buy power from the grid at a less expensive rate.

In 2003, a 1.5 MW combined heat and power (CHP) system was installed at One Market by Northern Power Systems. The system consists of three 500-kW Waukesha gas engines with waste heat recovery, which produces 1800 kg of steam per hour. The waste heat from the engine cooling water and the exhaust is converted into steam for heating the building.

The system operates at near capacity for maximum efficiency and provides approximately 30% of the complex's annual electricity demand. The captured heat displaces 85% of the natural gas needed for steam boilers. The installation at One Market is the first of its kind to in a metropolitan area and is one of the largest to be interconnected to the grid in the US. Initially, Pacific Gas and Electric (PG&E) did not allow for the operation of an onsite generator in the downtown San Francisco area due to concerns of risks associated with operating with the "network" grid topology, but once safety could be assured, the project was given approval. The system is also upgraded to serve as backup power during blackouts.

Financial Incentives

In order to quality for the California Public Utility Commission's (CPUC) Self–Generating Incentive Program, which provided for 30% of the capital costs, the system needs to provide a combined electrical and thermal efficiency of 62%. The engine itself runs at 32% efficiency in converting to electricity. Another 30% was achieved through the recovery of the heat from the exhaust.

One Market Plaza

500 kW Waukesha VGF generation set

Heat Recovery Steam Generator

Interconnection and Rule 21

Intertie M-3520 regulator

At One Market Plaza, an Intertie protection relay is used to regulate abnormal voltage and frequency of the power flows from the generators to the building's electrical network. The system also helps to prevent back-feeding into the city's grid. Utilities like PG&E have taken extensive measures to prevent this as it would poses a risk to both the system itself and anyone working on it when the utility grid is down. The installation complies with the CPUC's Rule 21, which specifies interconnection standards for distributed generation. The rule is not limited to CHP systems but also includes solar, wind, and hydro systems that work in parallel with the existing grid. Although many states now have interconnection standards, they have in some cases been problematic due to open interpretation.

Installation Challenges

After reviewing the energy needs, economics, existing electrical and mechanical systems of the complex, the engineers decided that One Market Plaza was an ideal site for distributed generation. However, due to the lack of a centralized plant and the lack of physical space, one of the main challenges was determining the location for housing the generators. Working with facility managers who were aware of the needs and outputs of CHP systems, the engineers at Northern Power considered various options. Initially, the team had procured adjacent parking spaces for accommodating the equipment but due to losses in rental revenues, it was decided that a room in the basement that formerly housed backup generators was amenable for the CHP system. Nevertheless, in order to properly accommodate all the auxiliary equipment, the heat-recovery steam generators (HRSG) and the gas metering apparatus were housed in rooms above the gen-sets. In addition, various engineering requirements were met for ventilation, accessibility, and for interfacing with the existing electrical network.

Further information can be found at

One Market Plaza:
http://www.emporis.com/en/wm/cx/?id=105824
Northern Power Systems, Inc:
http://www.northernpower.com

PRAC: www.chpcenterpr.org

Version 1.1 2/12/07

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At One Market, the incentives pay for 30% of the capital costs as long as the system provides an overall electrical and thermal efficiency of 62%.

"The engines run at approximately 32% efficiency. The other 30% is obtained through recovering the heat of the exhaust and converting it into usable thermal energy."
Chach Curtis, Vice President of onsite generation for Northern Power Systems Inc.

PACIFIC REGION CHP APPLICATION CENTER

combined heat & power in a luxury hotel

The Ritz-Carlton in San Francisco

240 kW microturbine/abs. chiller system

Project Profile

Quick Facts

Location:
San Francisco, CA

Capacity:
PureComfort™ system from UTC Power with 240-kW (four 60-kW Capstone C-60 microturbines)

Fuel: Natural gas

CHP system:
120 RT double-effect absorption chiller from Carrier Corp.

Chiller performance: >1.3 COP

Noise: <65dBa at 30 feet with sound suppression system

System Online: October 2005

Total Project Cost: $1,012,640

Energy Cost Savings:
Approximately $120,000/year

Estimated Payback Time:
8 years (without incentives), under 3 years with incentives

Funding Sources:
Host Hotels and Resorts, CA Self-Generation Incentive Program, and U.S. Department of Energy

Project Overview

The Ritz-Carlton San Francisco is the city's highest-rated hotel, located in the upscale Nob Hill area. This luxury hotel, which is owned by the Host Hotels and Resorts, accommodates 336 guest rooms, Fitness Center, indoor pool, whirlpool, and steam rooms.

A plan to lower energy consumption and reduce energy expenses for the hotel resulted in the purchase of the PureComfort™ 240 Combined Cooling, Heating and Power (CCHP) package from UTC Power Company. This system includes four 60-kW Capstone microturbines, running on natural gas, with the exhaust collected in a manifold and used to drive a 120 refrigeration tons (RT) double-effect chiller from Carrier Corporation (a sister company from UTC Power). The peak electricity demand at the Ritz-Carlton is 1 MW and chilling requirements can reach almost 300 RT. The PureComfort™ solution provides 240 kW of power and 120 RT of chilling and is therefore able to run base-loaded for the entire year, resulting in near maximum overall efficiency for this type of system. The system is designed to satisfy the base-load chiller demand for the whole year and run the chiller in the most efficient mode. The PureComfort™ solution is able to achieve an overall fuel utilization of greater than 80%.

Originally, the hotel used a 300 RT electric chiller. This was relatively inefficient because it had to run 24 hours a day year-round, even though typical chilling needs were well below its capacity – only about 100 RT for eight months of the year. Operated in this way, the chiller accounted for about 20% of the hotel's total electricity use. The new configuration - using the absorption chiller - allows for shutting off the 300 RT chiller for eight months of the year. The overall net energy cost saving is estimated at $120,000 per year.

Costs & Financial Incentives

- Microturbines: $224,640
- Heat exchanger unit: $141,000
- Mechanical and electrical: $502,000
- Consulting: $16,000
- Project management: $77,000
- Other costs: $52,000 **Total: $1,012,640**

To mitigate these costs the Ritz-Carlton has received a $150,000 rebate from California's Self Generation Incentive Program (SGIP) as well as a $500,000 grant from the U.S. Department of Energy for installing an advanced CHP demonstration project.

The picture to the left shows the four C-60 Capstone microturbines. The absorption chiller is oversized to 300 RT and currently delivers a maximum of 120 RT, giving the Ritz-Carlton the possibility of adding additional microturbines without the need to change the chiller.

To ensure the luxurious ambiance for guests of the five-star hotel, CHP system noise and visibility was a major issue. The picture to the right shows the view from the cocktail lounge towards the microturbine system. The system is placed behind the white wall and does not affect the guests' view.

UTC Power PureComfort™ System

The PureComfort™ 240M microturbine-based CHP solution is one of three available standard packages from UTC Power. Other available packages include the 300M and 360M systems, with 300 or 360 kW of power output rating. Each system consists of a double-effect absorption chiller/heater from Carrier Corporation and four to six 60-kW microturbines. This standardized approach reduces system costs and results in an average overall thermal efficiency of greater than 80%. The relatively quiet system (65dBa @ 30 feet with sound suppression system) consists of the core microturbine units with height of 83", width of 30", length of 77", and weight of 1,700 lb., as well as the chiller with a height of 82", width of 79", length of 145", and weight of 18,544 lbs. The system emits less than 0.49lb/$MWh_{electricity}$ of NOx.

PureComfort™ 240 System	Hot Day (ARI Cond.)	ISO Day (59° F.)	Cold Day (32° F.)
Net Power [kW]	193	227	231
Cooling Output [RT]	124	142	
Heating Output [MBh]			1,100
Net System Effic. [% LHV]	80	91	68

Note: ARI conditions are 95° F. outdoor temperature, 44° F. chilled water output, and 85° F. condensed water input

Typical performance values for the 240M system under different conditions are shown in the table to the left.

Further information can be found at

The Ritz-Carlton, San Francisco: http://www.ritzcarlton.com/hotels/san_francisco
UTC Power: http://www.utcpower.com
Microturbines: www.capstoneturbine.com
Carrier Corporation (absorption chiller): http://www.corp.carrier.com
PRAC: www.chpcenterpr.org

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The 240 kW "Pure Comfort" microturbine system at the Ritz-Carlton saves enough electricity to power 200 average American households.

The CHP system installed at The Ritz-Carlton reduces emissions of 800 tons of CO_2 per year. This is equivalent to removing 140 cars from California roads.

PACIFIC REGION CHP APPLICATION CENTER

combined heat & power in waste water treatment

Chiquita Water Reclamation Plant

120 kW microturbine CHP system

Project Profile

Quick Facts

Location: Santa Margarita, CA

Capacity: Four Capstone C30 Biogas 30kW microturbines and one Microgen™ hot water generator

Fuel: Anaerobic digester gas

CHP system: Digester heating

System Online: December 2001 (Phase 1), 60 kW upgrade in October 2003 (Phase 2)

System Efficiency: Electric efficiency is around 20% to 22%

Total Project Cost: Phase 1 installation costs of $114,020 plus South Coast Air Quality Management District (SCAQMD) support; Phase 2 installation costs of $160,582

Energy Cost Savings:

Estimated $60,000/year (for Phase 1)

Expected Payback Time:

2 years for Phase 1 with the SCAQMD support

Funding Sources: Santa Margarita Water District and SCAQMD donation

Project Overview

Two Capstone 30 kW microturbines integrated with one Microgen™ hot water generator (HWG) were commissioned at the Santa Margarita Water District (SMWD) Chiquita Water Reclamation Plant in December 2001.

Two additional 30 kW microturbines were commissioned and the HWG was modified in October 2003. The original two Microturbines (Phase 1) were donated by the South Coast Air Quality Management District (SCAQMD) as part of their program to provide clean auxiliary power during periods of peak demand on the grid.

The microturbines are fueled by anaerobic digester gas from the reclamation plant. Waste heat from the microturbines is used to heat the anaerobic digesters. SMWD chose to operate their original microturbines full time, realized significant monthly cost savings and thus decided to independently acquire its second two microturbines (Phase 2).

The systems are all base loaded at full electrical power and typically deliver 26-30 kW each. Waste heat from the first two microturbines was sufficient to allow shutting down the two boilers that originally fed hot water to the digesters, although one boiler is kept in standby mode. Additional heat provided by the newer microturbines may be used to dry sludge in order to lower shipping costs and/or heat future anaerobic digesters.

Costs & Financial Incentives

The SCAQMD program supporting the original installation began in April 2001. The Chiquita Water Reclamation Plant microturbines were actually commissioned in December 2001. Phase 1 construction costs added up to $83,666, not including change order costs. Other costs included interconnection ($1,400 for four turbines), SCAQMD permits ($1,611 for two turbines) and emissions source testing ($9,520 to test one representative turbine). Total Phase 1 installation costs ultimately added up to $114,020, excluding the cost of the equipment donated by SCAQMD.

In March 2003 SMWD was granted a location specific permit exemption by SCAQMD. SMWD pointed out that burning digester gas in microturbines is more environmentally friendly than the alternatives, including fueling boilers, reciprocating internal combustion engines or simply flaring the gas. It took 16 weeks to finalize an interconnection agreement with San Diego Gas and Electric.

The Phase 2 microturbines and modified Microgen™ hot water generator were commissioned in October 2003. Total installation costs for Phase 2 were $160,582.

Picture below: Microturbines

Picture above: Microturbine disconnection switches

Performance Summary

The Phase 1 installation generated net operating cost savings of $4,000-$5,000 per month. As of May 2003, after 11 months of continuous operation, SMWD estimated total operating savings due to the microturbines to be approximately $58,300. Also as of May 2003 these two microturbines had each logged approximately 10,800 operating hours.

As of December 18th, 2003, the Phase 1 and Phase 2 microturbines had logged approximately 12,800 and 1,500 operating hours, respectively. SMWD operators estimate 99% availability for the microturbines. The most common reliability problems are centered around the fuel cleanup and delivery system.

Efficiency can be difficult to measure as anaerobic digester gas composition and heat utilization can fluctuate. However, based on a typical digester gas heating value of 60% of natural gas the electric efficiency is approximately 20-22%. Fuel compression requirements represent significant parasitic power loss. Up to 1 MMBTU/hr (293 kW) of heat is utilized. Emissions tests performed in 2002 indicated emissions levels of 1.25 ppmv NO_X and 138.5 ppmv CO, corrected to 15% O_2, from one microturbine operating at full power.

Lessons Learned

Lessons learned from both project phases include: (1) Installation costs for these systems were very significant in relation to the cost of the generators themselves; (2) Placing a robust fuel treatment system upstream of the microturbines was important (the new installation includes a refrigerated dryer and SAG™ filter system for cleaning and drying the digester gas - landfill gas can contain siloxanes and burning converts them to silica particles, which are abrasive and clog conventional combustion engines); (3) Integration of the heat exchanger with the microturbines was not trivial.

Further information can be found at

Santa Margarita Water District:
http://www.smwd.com/ Ron Meyer (949) 459-6594
South Coast Air Quality Management District:
http://www.aqmd.gov/
Methane (Biogas) from Anaerobic Digesters:
http://web.archive.org/web/20041124201613/www.eere.energy.gov/consumerinfo/factsheets/ab5.html?print
PRAC: www.chpcenterpr.org Version 1.2 12/19/06

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To be able to produce digester gas from cool waste water the digester has to be heated. The necessary heat is captured from the microturbines, which increases the overall energy efficiency of the system.

Important for a well functioning system is a H_2S scrubber (filter) which reduces the corrosive hydrogen sulfide content in the biogas. Failure to scrub H_2S could reduce the engine lifetime considerably.

PACIFIC REGION CHP APPLICATION CENTER

combined heat & power in a jail

Alameda County Santa Rita jail

1 MW fuel cell CHP system

Project Profile

Quick Facts

Location: Dublin, Alameda County, CA

Capacity: 1 MW DFC1500 molten carbonate fuel cell (single module with four internal stacks)

Fuel: Natural gas

Noise Level: <70dB @ 10 feet

CHP system:

Waste heat for hot water and space heating

Construction Time: 7 months

System Online: May 2006

Total Project Cost:

$6,100,000 (without incentives or maintenance/stack replacement contract with Fuel Cell Energy)

Energy Cost Savings:

$264,000/year

Expected Payback Time:

14 years (with incentives)

Overall System Efficiency: 58%

Funding Sources:

Alameda County; CA PUC Self-Generation Incentive Program; U.S Department of Defense

Project Overview

In 1989, the Santa Rita jail was reopened at a 113-acre facility. Today, the jail holds about 4,000 inmates on 23 acres (9.3 hectares) and is considered the third largest county detention facility in California. Operating the facility is very resource and energy intensive. On food alone, they spend about $500,000 a month to produce 12,000 meals a day. The estimated electricity peak demand is 3.2 MW and therefore there is public pressure to make the operations more efficient. Alameda County has had a long history of using innovative approaches to increase energy efficiency and reduce public costs.

In May 2006 the County installed a 1 MW molten carbonate CHP fuel cell system in order to provide reliable onsite off-peak/base electricity and hot water pre-heating for domestic hot water needs. The system provides 8 million kWh/yr electricity (about 50% of demand) and 1.4 MMBtu/year of heat (410 kWh/yr = 18% of demand).

Prior to installing the fuel cell, in Spring 2002, the County put in a 3-acre (1.2 hectare) 1.2 MW solar system on the roof of the Santa Rita jail. In addition, the jail uses cool roof membranes and a "Demand Response Smart Control System" to manage the electricity demand of the facility.

Chevron Energy Solutions designed and managed the project and FuelCell Energy is responsible for ongoing maintenance. The single 1 MW DFC1500 480V AC system from FuelCell Energy was assembled on-site and is 26.5 feet (8m) high, 43 (13.1m) feet wide, and 40 feet (12.2m) long. The fuel cell power plant removes roughly 3000 tons of CO_2 emissions per year, which is equivalent to removing 520 cars from California roads or planting 830 acres (336 hectares) of forest.

Costs & Financial Incentives

The total project costs are estimated to be $6.1 million, including operating and maintenance costs. Alameda County signed a maintenance agreement with FuelCell Energy for 13 years. This agreement includes fuel cell stack replacements every 4-5 years and other periodic maintenance with average costs of about $200,000 to $300,000 per year. In the course of the fuel cell stack replacements, the rated capacity will increase to at least 1.2 MW because of expected technical improvements in stack technology. The overall system lifetime is estimated to be 25 years, with total savings of $6.6 million over that time ($264,000 per year). To mitigate the $6.1 million in capital costs, Alameda County received $1.4 million from Pacific Gas and Electric through the California Self-Generation Incentive Program and $1.0 million from the U.S. Department of Defense's Climate Change Fuel Cell Program.

How does a molten carbonate fuel cell work?

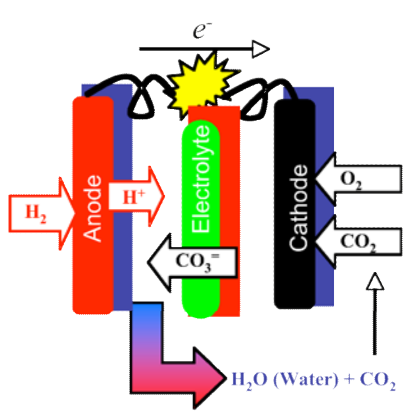
A fuel cell converts energy stored in a fuel and an oxidant into electricity through chemical reactions in the cell. In molten carbonate systems, these following reactions occur at the anode and cathode:

$$Anode: H_2 + CO_3^{=} \Rightarrow H_2O + CO_2 + 2e^-$$

$$Cathode: \tfrac{1}{2}O_2 + CO_2 + 2e^- \Rightarrow CO_3^{=}$$

This electrochemical conversion requires neither combustion nor any moving parts and unlike batteries, fuel cells do not store energy. Molten carbonate fuel cells have among the highest efficiencies of conversion (up to 60%); however, they require high temperatures, typically at 600 °C (1250 °F). At these high temperatures, non-precious metals can be used to catalyze the reaction, substantially bringing down the costs. On the anode, H_2 diffuses onto the anode catalyst (metal plate), which dissociates it into hydrogen (H^+) ions and electrons (e^-). At the cathode end, the electrons combine with oxygen (O_2) and carbon dioxide (CO_2) to form carbonate ions ($CO_3^{=}$) that diffuse through a molten carbonate electrolyte. When the $CO_3^{=}$ meets the H^+, water and CO_2 are formed, completing the flow of electrons.

Schematic of Molten Carbonate Fuel Cell



Above: 1 MW single direct fuel cell module at the Santa Rita jail

Below: Alameda County Transit operates three zero-emission fuel cell buses on a regular schedule

Further information can be found at

Alameda County: www.acgov.org/gsa/energy.htm
Chevron Energy Solutions: www.chevronenergy.com
FuelCell Energy: www.fuelcellenergy.com/
Hydrogen, Fuel Cells and Infrastructure Technologies Program:
http://www1.eere.energy.gov/hydrogenandfuelcells/
Fuel Cell bus:
www.actransit.org/environment/hyroad_main.wu

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The fuel cell will provide about 50% of the jail's annual energy needs.

"A megawatt of power from the fuel cell covers base load electricity. And by pairing the plant with a solar array for peaking power, and utilizing waste heat for hot water, the entire system delivers the highest energy efficiency possible, while improving reliability"

R. Daniel Brdar, president and chief executive officer from FuelCell Energy.

Sierra Nevada Brewery

1MW fuel cell CHP system

PACIFIC REGION CHP APPLICATION CENTER

Project Profile

combined heat & power in a brewery

Quick Facts

Location: Chico, California

Capacity: 1 MW (four 250-kW FuelCell Energy DFC300A molten carbonate fuel cells)

System Online: 2005

Hydrogen Production Method: Digester gas from brewing process

H_2- Production Capacity: Approximately enough to fuel one 250-kW fuel cell

System Efficiency: Estimated 50% electric efficiency, 75% using CHP

Total Project Cost: $7 million over five years

Expected Electricity Cost Savings: $400,000/year

Expected Payback Time: Approx. 6 years (with incentives and using digester gas)

Funding Sources:
Sierra Nevada Brewery
CA Public Utilities Commission

Project Overview

Sierra Nevada Brewing Co. (SNBC) in Chico, California is producing methane and electricity from byproducts of the company's beer brewing process. Founded in Chico in 1980, Sierra Nevada applies resource conservation and reusing/recycling raw materials as guiding operating principles.

The brewery has installed four 250-kW direct fuel cells that run off a combination of natural gas and methane produced from the brewery's wastewater anaerobic digester.

The treatment of SNBC's effluent water takes place on-site and uses a two-step anaerobic and aerobic digester process that produces methane. The methane is then captured and piped to the fuel cells where it is mixed with natural gas from the pipeline. The fuel cells are high-temperature molten carbonate units from FuelCell Energy Inc. They are providing a substantial portion of the facility's baseload power. The waste heat is being collected as steam and used for the brewing process as well as other heating needs onsite. The fuel cells initially ran off of natural gas alone, but in late 2006 the digester gas was integrated into the project, thus displacing 25-40% of the natural gas use with the digester gas. The fuel cell system was installed by Alliance Power, a distribution partner of FuelCell Energy. Alliance Power performed all aspects of the initial project implementation, including siting, planning, permitting, designing, constructing, financing, and operating. SNBC purchased the fuel cells from Alliance Power in December 2006. FuelCell Energy continues to provide cell monitoring and servicing.

Financial Incentives

The total project cost for the first five years is approximately $7 million, including installation costs and operation and maintenance for the hydrogen production system and the fuel cells. Some of the project costs were offset by $2.4 million in funding from Pacific Gas and Electric Co. through the California Public Utility Commission (CPUC) Self Generation Incentive Program and $1 million from the U.S. Department of Defense Climate Change Fuel Cell Program. With these subsidies, an estimated electricity cost savings of about $400,000 per year, and other cost savings associated with the operation of the system, project managers expect a payback time of about six years.

California Self Generation Incentive Program

CPUC/PG&E's Self-Generation Incentive Program provides financial incentives to help support the costs of on-site electric generating systems utilizing either solar, wind, fuel cell, micro turbine or internal combustion engine cogeneration systems. Program participants are eligible to receive incentives under this program for installing distributed generation technologies based on system type, size, fuel source and out-of-pocket costs. Only commercially available and factory new equipment is eligible for incentives. Rebuilt or refurbished equipment is not eligible to receive incentives under this program. The maximum system size is 5 MW (and the incentive payment is capped at 1 MW).

Example SGIP Incentive Levels for Advanced Technologies (as of July 1, 2006)

Level	Technology	Incentive	Eligible Size Range
Level 1	Solar photovoltaic	$2.80/Watt	30 kW – 5 MW
Level 2	Renewable fuel cells	$4.50/Watt	30 kW – 5 MW
	Renewable micro-turbines	$1.30/Watt	No min size – 5 MW
Level 3	Non-renewable fuel cells	$2.50/Watt	No min size – 5 MW
	Non-renewable microturbines	$0.80/Watt	No min size – 5 MW

Further information can be found at

Sierra Nevada Brewery: www.sierranevada.com
Alliance Power, Inc: www.alliancepower.com
FuelCell Energy, Inc: www.fuelcellenergy.com
Self-Generation Incentive program: www.pge.com/suppliers_purchasing/new_generator/incentive/index.html
PRAC: www.chpcenterpr.org

Version 1.4 5/29/07

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"Like any business, Sierra Nevada was looking for stable, affordable, reliable power, and they wanted to limit the environmental impact of their operation. They found the answer in a hydrogen fuel cell that generates power on site."
Arnold Schwarzenegger Governor of California

Air quality improvement is equal to an elimination of 500 gasoline cars.

The overall energy efficiency of the installation is double compared to grid-supplied power.

PACIFIC REGION CHP APPLICATION CENTER

Transamerica Pyramid Building

1 MW CCHP System

Project Profile

combined cooling heat & power in a skyscraper

Quick Facts

Location: San Francisco, California

Capacity: 1 MW (two 500-kW Waukesha VGF L36GSID natural gas-fired V-12 engine systems)

System Online: 2007

Fuel: Natural gas

Exhaust: 3-way catalytic converter

Chiller: York 320-ton water absorption

System Efficiency: Estimated 50% overall efficiency (providing heating, cooling, electricity)

Power Output: 71% of electricity (some for displaced cooling), and 100% of steam demand

State Rebate: 13% of capital costs

Expected Payback Time: 4 to 5 years (simple payback with incentives)

Funding Sources:
California Public Utilities Commission SGIP

Project Overview

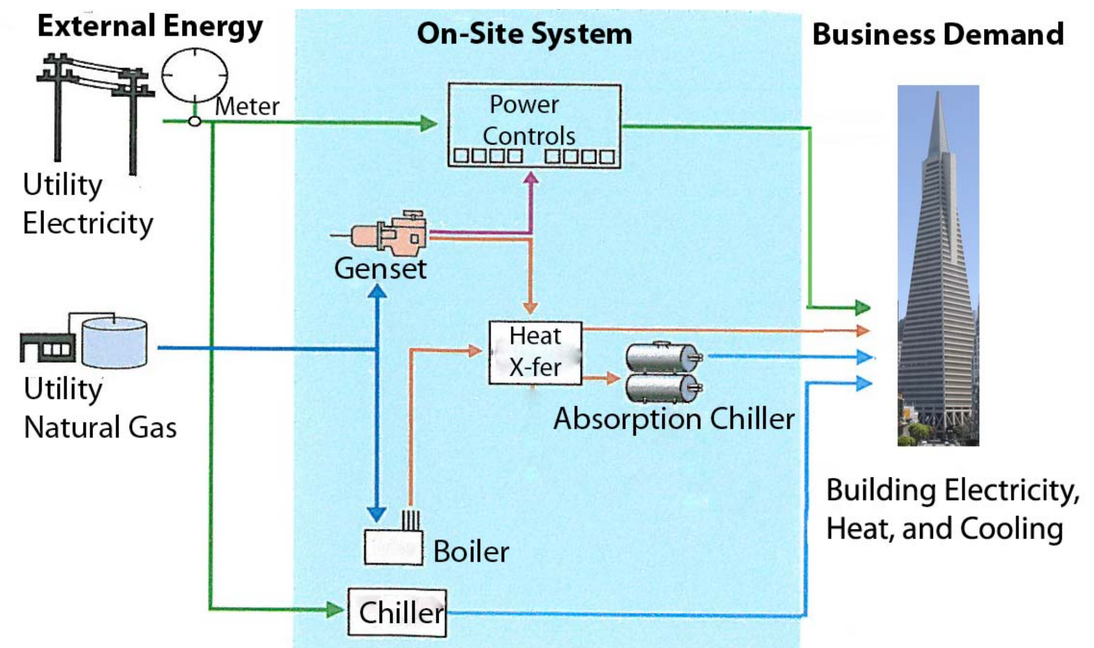
The Transamerica Pyramid Building at 600 Montgomery Street is the tallest and most recognizable building in the San Francisco skyline. Built on the former location of the historic Montgomery Block, construction was completed in 1972. The 48-story building houses office and retail space, although is no longer the headquarters of Transamerica Corporation for which the building is named. With the increasing cost and decreasing reliability of the San Francisco downtown steam utility, commercial buildings have begun to find ways to provide heat in a more reliable and cost-effective manner. The on-site Combined Cooling, Heating and Power (CCHP) system eliminates demand for city steam and reduces demand for electricity from the utility. Using less electric power during peak times enables the building to buy power at a lower average rate.

Installed by Distributed Energy Systems in 2007, this CCHP system is comprised of 1 MW of cogen units in total (two 500-kW Waukesha engines) along with a 320-ton absorption chiller.

Financial Incentives and Performance

Public funding was provided through the California Public Utility Commission's (CPUC) Self–Generating Incentive Program, which paid for 13% of the capital costs. The system produces a combined electrical and thermal efficiency of approx 50%. The engine itself runs at 27% overall electrical conversion efficiency. An additional 23% is achieved using the recovered waste heat for building water and space heating and cooling.

The system operates at near capacity for maximum efficiency and provides approximately 70% of the complex's annual electricity demand. The captured heat displaces 100% of the steam formerly provided by San Francisco's steam utility. The installation is required by interconnection agreement to power down upon grid failure, but could in the future be upgraded for blackout ride-through capability.



York Absorption Chiller

Absorption Chiller

The vast majority of the combustion heat from the generator goes to power the York absorption chiller. This single, freight car-sized component is so massive that the floors of the basement room where it is installed had to be reinforced. Walls were built around the chiller once in place. The York unit has a 500-ton cooling capacity operating on steam, and in this case, a 320-ton capacity operating on the heated jacket water and recovered waste heat from the exhaust of the gen-sets.

Installation Challenges

Locating the Transamerica's CHP system in the basement was assuredly going to require supplementary cooling to remove the unused waste heat from the building. Before installation, two large cooling towers served the facility, and the proposed CCHP system would have required a third at street level as the plans were initially drawn. However, both the SF city planning department and the owner of the building thought it better to preserve the historic building's aesthetics, so an electrical compressor chiller to reject waste heat from the CHP unit now serves to cool the basement rooms housing the gensets. The space to locate the absorption chiller close to the cogen unit was not available, so heat is transferred from the cogen unit via the jacket water traveling the perimeter of the underground parking unit to the York chiller located across the building and one floor away. Exhaust emissions from burning natural gas can be a concern in urban environments, and in this installation a three-way catalyst is used to clean up air pollutant emissions to meet the 2007 Bay Area Air Quality Management District's standards.

Further information can be found at

Pyramid Building:
http://en.wikipedia.org/wiki/Transamerica_Pyramid

Distributed Energy Systems (formerly Northern Power Systems, Inc.):
http://www.distributed-energy.com/

PRAC: http://www.chpcenterpr.org

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Univ. of California - Berkeley

25 MW CHP System

PACIFIC REGION CHP APPLICATION CENTER

Project Profile

combined heat & power on a university campus

Quick Facts

Location: Berkeley, California

Capacity: 24-26 MW combined-cycle (21.35 MW GE LM2500 gas turbine-generator configured with 5 MW Terry steam turbine-generator)

System Online: 1987

Fuel: Natural gas

System Efficiency: Approx 11,200 Btu/kWh heat rate for CC plant (30.5% electrical effic.), with overall thermal efficiency estimated at 50-55%.

Waste Heat Use: 185,000 lbs/hr of steam delivered to campus steam loop

Availability: 96% on average

Financial Arrangement:
Long-term (30 year) lease arrangement for CHP plant and building between campus and PE-Berkeley Inc., with power sales agreement with PG&E. Original capital cost estimated at $32-34 million. Economic benefits to campus from backup generation capacity and minimized utility costs

Project Overview

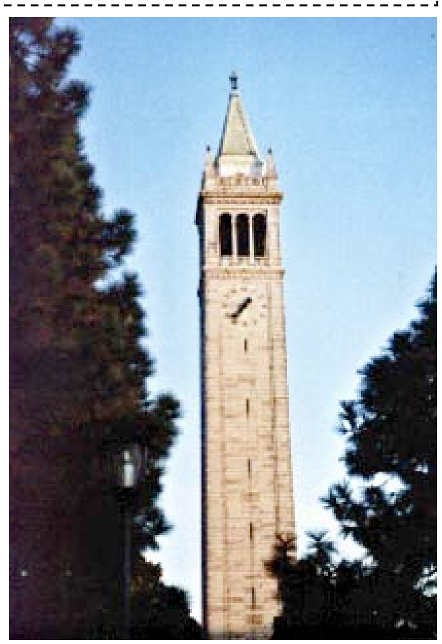
The University of California – Berkeley has a classic combined heat and power (CHP) system, based on the combination of a 21.35 MW General Electric gas powered turbine-generator and a 5 MW Terry Corp. steam-powered "bottoming cycle" turbine gen-set. The system was installed in the mid 1980s at a time when CHP (known as "cogeneration the time) was first being widely encouraged in California, and went online in 1987.

Waste heat from the gas turbine provides steam to replace one of the older boilers that was replaced to help make room for the CHP plant. Up to 185,000 pounds of steam per hour can be generated, or approximately $4MW_{TH}$. Supplemented by three additional conventional boilers, the steam loop provides heat to the entire central campus along with other buildings on the north, east, and south sides of campus including the stadium, Greek theater, and campus art museum.

The CHP system can operate using diesel fuel along with other campus generators as a backup power source, in the event of a failure in PG&E's supply of grid power. This enhanced reliability is important for campus laboratories and data systems, as well as for its role as an emergency shelter facility for the community.

In 1998, the CHP system was upgraded from "LM2500 PE" to "LM2500 PH," with "full STIG" (steam-injected gas turbine). This means that increased rates of steam can be injected in the gas turbine to improve power output and efficiency, with the added benefit of reduced emissions.

Under an agreement with PG&E, the power generated by the CHP plant is delivered to the utility grid under a power purchase agreement – but of course the majority of the power is actually consumed locally on campus. UC Berkeley gets a low, but not special, electricity rate from PG&E's "E20T" rate schedule because it connects with the grid at transmission level voltage, making for a more efficient connection to the grid.



Historic Campanile Tower

UC Berkeley Campus CHP Plant

Emissions Considerations

The campus steam output from the three remaining conventional boilers has been de-rated from 100,000 pounds per hour to 80,000 pounds per hour, per boiler, due to emissions concerns and the reduction possible from the somewhat lower output. Emissions from the CHP plant itself are controlled through a comprehensive environmental plan that exceeds regulatory compliance. For example, the system currently operates with emissions of around 15ppm of oxides of nitrogen (NO_X), even though the permitted limit is 20ppm. This compares to the original (1987) limit of 42ppm. The campus received quick approval for the facility by the local air district because the CHP system allows the aging conventional steam generation equipment to be operated as backup rather than as the primary sources of steam, thereby providing a "greener" overall solution.

Looking Ahead – Future Cogeneration at UC Berkeley?

The 30-year lease agreement for the operation of the CHP plant expires in 2017, at which time the campus will be at a crossroads. The campus electrical load has grown to about 40 MW with several buildings added in recent years. The campus CHP and boiler plant can presently meet all of the campus thermal load but not all of the electrical load. This means that in theory the current CHP system could be replaced with a larger one, where more of the steam output could come from cogeneration and less from conventional steam boilers. The campus electrical needs would then be more fully met with onsite generation.

Ideally, the campus would design and commission a new CHP plant to come online by the time the old plant is decommissioned in 2017. Unfortunately, a new site immediately adjacent to the old one is not available, so a key issue is to identify a site for a new plant so that the old facility – dating back to the 1930s – can be decommissioned and replaced.

Further information can be found at:

PE-Berkeley, Inc.:
http://www.deltapower.com/projects/california/berkeley.html

University of California:
http://www.ucop.edu/facil/sustain/greenbldg.html

*PRAC: http://*www.chpcenterpr.org

Version 1.2 9/23/08

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The classic CHP plant on the UC Berkeley campus helps meet campus energy needs, while also helping to provide enhanced reliability.

However the system is more than two-thirds of the way through its design life and the campus faces a choice about what to do in the future.

Other UC campuses have similar but more modern systems that are also saving energy and money.

PACIFIC REGION CHP APPLICATION CENTER

Univ. of California – San Diego

30 MW CHP System

Project Profile

combined heat & power on a university campus

Quick Facts

Location: San Diego, California

Capacity: 30 MW combined cycle (two 13.5 MW Solar Turbines Titan 130 gas turbine gen-sets configured with a 3 MW Dresser-Rand steam turbine)

System Online: 2001

Fuel: Natural gas

System Efficiency: Approx 10,250 Btu/kWh heat rate for the gas turbines with gross thermal efficiency estimated at about 70%

Waste Heat Use: 120,000 lbs/hr of steam used for domestic hot water and to drive a centrifugal chiller

Availability: 95% on average

Est. Annual Cost Savings: The campus estimates that the CHP plant provides $8-10 million per year in avoided costs

Financial Arrangement: Owned and operated by the campus Capital cost for the CHP project installation was about $27 million.

Project Overview

The University of California – San Diego has a combined heat and power (CHP) system, based on the combination of two 13.5 MW Solar Turbines Titan 130 gas powered turbine-generator and a 3 MW Dresser-Rand steam-powered "bottoming cycle" turbine-generator. The system came online in 2001.

The Solar Turbine units include three-stage, axial flow turbines with rotational speeds of up to 11,200 revolutions per minute (RPM), coupled with three-phase, wye-connected, synchronous, brushless generator units.

Waste heat from the gas turbine provides steam, which is used for various uses. The first use of steam is for cooling – using a steam driven centrifugal chiller. A 4 million gallon cold-water thermal storage system helps to meet peak campus cooling needs.

The second use for the steam is to produce domestic hot water for campus buildings located near the central plant. The third priority is to run the 3 MW Dresser-Rand steam turbine for additional electricity production as a "bottoming cycle." The system achieves about 70% gross thermal efficiency, in terms of the amount of electricity and steam produced.

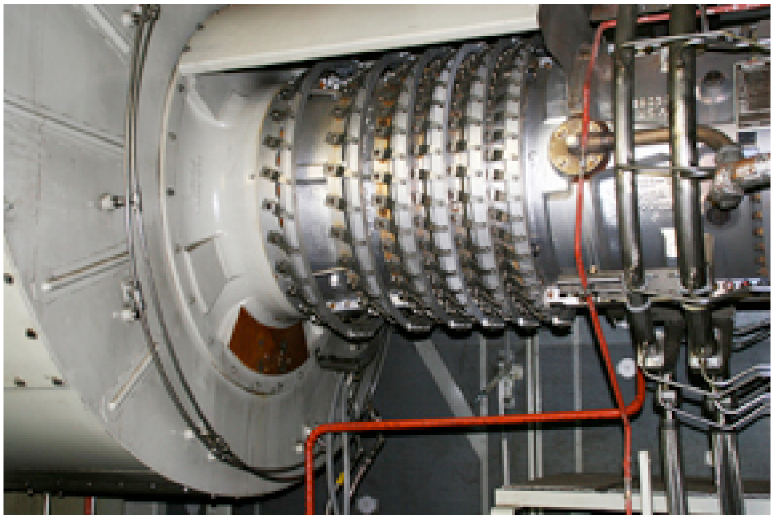
The CHP system was installed for about $27 million, or about $1,000 per kilowatt. The actual installation was performed under a third-party installation agreement with EMCOR Energy Services. Installation and interconnection with SDG&E went smoothly without major problems or issues.

Campus estimates that the system is saving approximately $0.04 per kWh compared with prevailing San Diego Gas and Electric Co. (SDG&E) rates, or about $8-10 million annually when boiler and chiller operational offset costs are also considered.

To meet campus load growth, a third Solar Turbines generator will be added in the near future. This is expected to be a 15 MW Titan 150 unit that, once added, will make the campus able to more fully meet its growing electricity and thermal energy needs.

UC San Diego Central CHP Plant

Solar Turbine Company Gas Turbine Unit



Cold Water Storage Tank

Emissions Considerations and the SoLoNO$_x$™ System

In order to address emissions concerns and the tight emissions regulatory control environment in California and other areas, Solar Turbines has developed the SoLoNOx™ system as an optional enhancement to the Titan 130 turbine gen-set package. At the UC San Diego site, the SoLoNOx™ system is controlling oxide of nitrogen (NOx) emission levels to about 1.2 ppm as an annual average, relative to a permitted level of 2.5 ppm.

The SoLoNOx™ is a called a "dry low emissions" system because it does not require water or steam injection. It makes us of a non-ammonia, passive catalyst that gets regenerated with periodic injections of hydrogen gas to scrub NOx from the catalyst and release it as inert nitrogen gas. The process uses lean, pre-mixed combustion technology and a uniform air/fuel mixture to carefully control the combustion process. Solar Turbines estimates that SoLoNOx™ has saved over 1.2 million tons of NOx emissions to date.

A Greening Campus – UC San Diego's Ambitious Efforts

UC San Diego is one of the leading campuses within the UC system in controlling the growth in campus energy needs through energy efficiency investments, developing renewable energy resources, and exploring other innovative clean energy schemes. The campus is installing approximately 1.2 MW of solar photovoltaic systems on parking garages and other buildings, is planning for the installation of a 2.4 MW high-temperature molten carbonate fuel cell system, and exploring the use of cold ocean water cooling at its Scripps Laboratory and other campus facilities.

The campus also has an agreement to purchase off-peak wind and to compensate by backing off the output of CHP plant – the first program of its kind so far in California – and has programs to analyze the energy use of data centers running on both AC and DC power, to study the prospects for bio-algae production as a fuel source, and to invest in additional energy efficiency programs.

Further Information Can Be Found At:

University of California – San Diego:
http://esi.ucsd.edu
http://sustain.ucsd.edu

Solar Turbines:
http://mysolar.cat.com/cda/files/154908/7/dscp-ucsd.pdf

PRAC: http://www.chpcenterpr.org

Version 1.4 9/30/08

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UC San Diego's CHP plant is providing up to 90% of the peak campus electrical demand and 75% of its steam demand, along with steam-powered cooling that can be stored in the nearby thermal storage system.

The campus estimates that the plant is providing savings of about $8 million per year compared with the prevailing electricity and gas utility rates in the area.

combined heat & power in a winery

PACIFIC REGION CHP APPLICATION CENTER

Vineyard 29

120 kW microturbine/chiller system

Project Profile

Quick Facts

Location: St. Helena, California

Capacity: 120 kW (two 60-kW Capstone C60 microturbine systems)

System Online: 2003

Fuel: Natural gas

System Efficiency: Estimated 82% overall efficiency

Emissions Reductions: 85%

Total Project Cost: $470,000

State Rebate: $120,000

Avoided Cost: $120,000 (backup gen.)

Expected Cost Savings: $25,000 to $38,000/year

Expected Payback Time: 6 to 8 years (with incentives)

Funding Sources:

Vineyard 29; California Energy Commission (CEC); CA Public Utilities Commission (PUC)

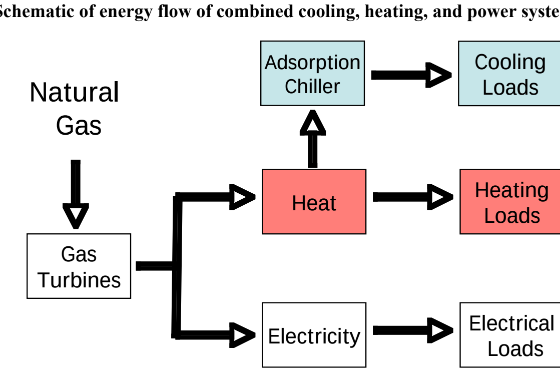
Project Overview

Vineyard 29 is in St. Helena, California in the Napa Valley wine growing region. Founded in 1989, the winery was sold to Chuck and Anne McMinn in 2000. Since then, the couple has made a commitment to sustainable practices that reduce emissions from their winery as well as toxins into the environment. Today, the winery processes 100 acres of grapes to produce about 10,000 cases of wine per year.

The winery has installed two 60-kW Capstone combined cooling, heating, and power (CCHP) microturbines that run on natural gas. With up to 120 kW of electricity produced by the systems, the co-generated heat is captured to produce hot water. To process each gallon of wine, three gallons of hot water are required. The water is also used to run the cooling system through an adsorption chiller. The chiller is needed to control the fermentation process and to run the air conditioning system during the summer time. In the wintertime, the hot water is also used to heat the building.

Vineyard 29 obtains all of its electricity from the CCHP system at half the cost it would take to power and heat their winery using conventional electricity and natural gas. The system has an overall efficiency of 82% when the waste heat recovery is included. The system has demonstrated an availability of 97% since commissioning, with only minor operational issues.

Schematic of energy flow of combined cooling, heating, and power system



Financial Incentives

The total project cost is approximately $470,000, including microturbines and chiller. Vineyard 29 received $120,000 in funding from Pacific Gas and Electric Co. through the California Public Utility Commission (CPUC) and the California Energy Commission (CEC). With these initial subsidies and the avoided costs of a backup generator (approx. $120,000) and a larger chiller ($20,000), the effective net capital cost was $210,000. The owners expect a payback of 6-8 years, reflecting an energy cost savings estimated at $25,000 to 38,000 per year.

Winery cave cooled by Nishiyodo chiller

Wine tanks heated by captured cogen. heat

Reducing environmental impacts

Among the innovations deployed at the CCHP system at Vineyard 29 is a 20-ton Nishiyodo adsorption chiller, the first of its kind to be installed in the US. Like conventional absorption chillers, adsorption chillers use recovered heat instead of electricity to produce cooled water. However, they do not require the use of lithium bromide (LiBr), an ozone-depleting coolant. Instead the cooling is achieved by using water as a refrigerant that is adsorbed onto a silica gel media. Then, under a low pressure of 7 kPa, heat is removed from the system by boiling off the water, yielding a stream of 30% propylene glycol/water mixture at 40°F for cooling the building, the cave, and the wine tanks. Not only are toxic chemicals avoided with this chiller, very little maintenance is needed. Overall, adsorption systems have a coefficient of performance (COP) of up to 75%.

In addition, a Dolphin pulsed power system is used in the EvapCo cooling tower. This advanced system disinfects water with pulsed power discharges. The process ionizes and purifies the water and prevents the buildup of scale. Unlike many water treatment systems, the Dolphin unit does not require the use of harmful germicides, which are often needed to prevent the proliferation of germs such as those that cause Legionnaire's disease. Moreover, fewer back-flushes are needed, significantly reducing water and energy demands of the system.

Nishiyodo adsorption chiller

Conduits for propylene glycol/water coolant

EvapCo cooling tower with electrostatic discharge

The overall energy efficiency of the installation is an impressive 82%.

"We produce 100% of the electricity that we use here at Vineyard 29. We do that at about half the cost of buying electricity and the natural gas we would need to run our boiler. At the same time, we are seven times less polluting than a PG&E power plant."
Chuck McMinn, owner of Vineyard 29

Further information can be found at

Vineyard 29: www.vineyard29.com
Capstone Power, Inc: www.capstone.com
Batt and Associates: www.fcs.net/batt
Axiom Engineers, Inc.: www.axiomengineers.com
PRAC: www.chpcenterpr.org

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2008 Combined Heat and Power Baseline Assessment and Action Plan for the California Market

Final Project Report

September 30, 2008

Prepared By:

Pacific Region Combined Heat and Power Application Center

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Legal Notice

Acknowledgments

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We also thank the PRAC Advisory Board members listed below for their helpful comments on earlier drafts of this report. Of course, the authors alone are responsible for the contents herein.

PRAC Advisory Board Members:

Kevin Best Real Energy	Charlie Senning The Gas Company
Keith Davidson DE Solutions, Inc.	Irene Stillings California Center for Sustainable Energy (formerly the San Diego Regional Energy Office)
Neil Dimmick Nevada State Office of Energy	Eric Wong Cummins Power Generation
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Table of Contents

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Executive Summary

The purpose of this report is to provide an updated baseline assessment and action plan for combined heat and power (CHP) in California and to identify the hurdles that prevent the expanded use of CHP systems. This report has been prepared by the Pacific Region CHP Application Center (PRAC). The PRAC is a United States Department of Energy (DOE) and California Energy Commission[1] sponsored center to provide education and outreach assistance for CHP in the Pacific region of California, Nevada, and Hawaii. The PRAC is operated by the University of California – Berkeley (UCB), the University of California – Irvine (UCI), and San Diego State University (SDSU).

The information presented in this report is intended to provide:

- an overview of the current installed base of CHP systems in California;
- a summary of the technical and economic status of key CHP system technologies;
- a summary of the utility interconnection and policy environment for CHP in California;
- an assessment of the remaining market potential for CHP systems in California;
- an "action plan" to further promote CHP as a strategy for improving energy efficiency and reducing emissions from California's energy system; and
- an appendix of contacts for key organizations involved in the California CHP market.

The California CHP Landscape

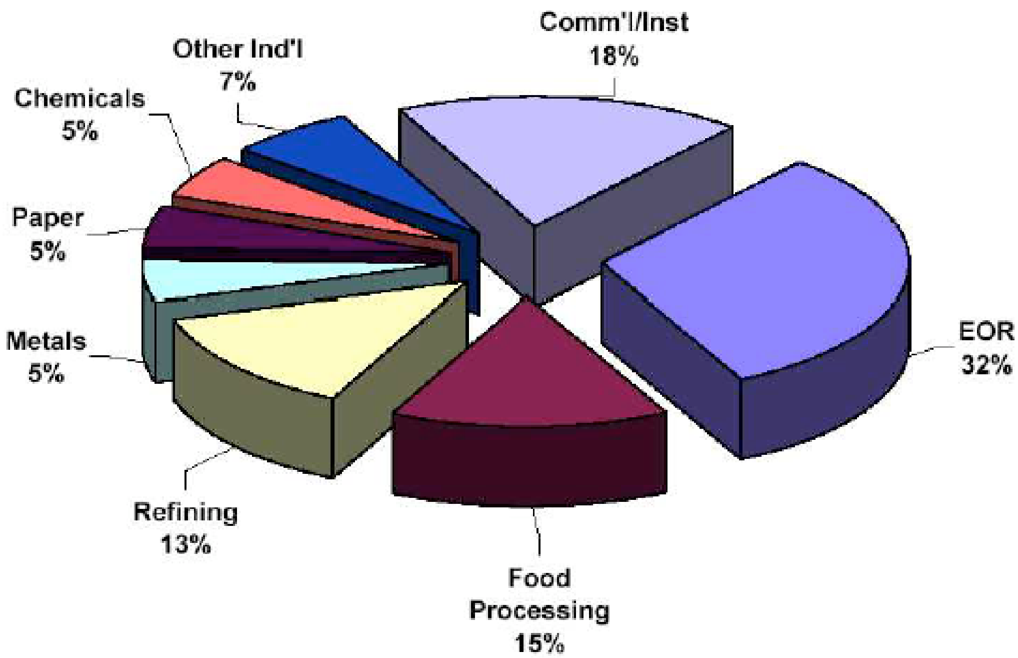
The Pacific region has several hundred CHP installations at present, with most located in California and in a wide range of industrial and commercial applications. The latest version of the Energy and Environmental Analysis Inc. (EEA) database of CHP installations in the state shows a total of 947 sites (Hedman, 2006). This total is uncertain because some of the older installations in the database may have become recently inoperable and because the database is not comprehensive with regard to new installations (particularly smaller ones). PRAC is working with EEA to update the database and improve its accuracy.

California currently has approximately 9 GW of installed CHP capacity, or 17% of total electricity generating capacity in the state.[2] Much of this capacity, about 8 GW, is in the form of relatively large systems (i.e., greater than 20 MW), with systems smaller than 20 MW accounting for only about 1 GW of the total capacity. The average capacity of Pacific region CHP installations is 10.7 MW (Hedman, 2006).

CHP systems in the western states of California, Hawaii, Nevada, and Arizona are estimated to be saving more than 370 trillion BTUs of fuel and 50 billion tons of CO_2 emissions per year, compared with the conventional generation they have replaced (Hedman, 2006). Figure ES-1, below, presents the breakdown of active CHP systems in California by application.

[1] Hereafter, the California Energy Commission is referred to as "the Energy Commission."
[2] Consistent with typical reporting, the capacity indicated herein reflects electrical generation only.

Figure ES-1: Composition of Active CHP Systems in California by Application



Source: Energy Commission, 2005a
Note: EOR is enhanced oil recovery

About half of the total CHP capacity (4,400 MW) is in the form of combustion turbines, with about a third (3,200 MW) in combined-cycle plants, about 900 MW in steam turbines, about 200 MW in reciprocating engines, and a few MW each for fuel cells and microturbines (Energy Commission, 2005).

California's electrical and natural gas services are provided by investor-owned utility companies (known as "IOUs"), municipal power organizations, and rural cooperatives. The major IOUs include Pacific Gas and Electric Company (PG&E), Southern California Edison (SCE), and the Sempra Group utilities Southern California Gas Company (SoCal Gas) and San Diego Gas and Electric Company (SDG&E).

Technical and Economic Status of Key CHP Technologies

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 ES-1, below, provides a summary of key characteristics of each of these types of generators.

Table ES-1: 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	Up to 85% (AE)	Up to 75% (AE)	Up to 75% (AE)	Up to 75% (AE)	Up to 90% (AE)
Emissions	Low (<9-50 ppm) NOx	Controls required for NOx and CO	Low when controlled	Potential for very low emissions	Very low to near 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 (GTI)	$0.007-0.015/kWh (GTI)	$0.005-0.01/kWh
Maintenance Interval	5,000-8,000 hrs	ID	40,000 hours	ID	ID

Source: Data from Energy Commission, 2007, except Gas Tech. Institute for O&M costs as noted by "GTI" and "AE" for author estimates

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.

Summary and Status of CHP Policy Issues in California

The policy context for CHP in California is complex and multi-faceted. The latest Energy Commission Integrated Energy Policy Report (or "IEPR" -- released in early 2008) summarizes many of these issues.[3] These are also summarized in this report, along with key recent developments.

In general, California has a well-developed policy for utility grid interconnection of CHP known as "Rule 21." This program prescribes processes for developing interconnection agreements

[3] The 2007 IEPR is available at: http://www.energy.ca.gov/2007_energypolicy/documents/index.html

with utilities, and sets time limits for various steps of the process. The Rule also ensures that interconnected CHP systems meet IEEE 1547 requirements for safe interconnection of CHP systems with utility grids.

Utility rates and standby fees are an important and controversial aspect of CHP, and one that is constantly changing. Each of the California IOUs has PUC-approved "cogeneration deferral rates" that allow them to offer a customer a discounted rate if they forego their cogeneration project. Further, at present, certain CHP systems are exempt from the reservation fee component of standby fees. This is explained in detail in section 5 of this report.

More generally, a potentially important issue for the development of CHP is the incentive structure for IOUs and other electric utility companies. These firms earn guaranteed but regulated rates of return on capital assets, in return for a geographic monopoly in the ownership of electricity generation assets, with some exceptions. Within this structure, existing or potentially attractive future CHP installations represent opportunities for guaranteed profitable investments that have been forgone. For this reason, CHP developers often believe that IOUs adopt rules and tariffs that discriminate against CHP projects. Important among these are standby charges. IOUs tend to deny these allegations, with arguments that attempt to rationalize their rates and incentive structures. This is an ongoing topic of significant importance to CHP markets that deserves further research.

Another important policy aspect of CHP in California is a recent change in the state incentive program for CHP installation. At present, California has a specific program for this, known as the Self-Generation Incentive Program or "SGIP," that historically has provided capital cost buy-down incentives for CHP systems that could be combined with federal tax programs such at the federal investment tax credit for microturbines.

At the end of 2007, the SGIP program for combustion-based technologies was allowed to expire with the passage of Assembly Bill 2778 (Lieber, Statutes of 2006, henceforth "*AB 2778*"), signed by Gov. Schwarzenegger in September of 2006. The *AB 2778* bill extended the SGIP program through 2011 for wind and fuel cell technologies, but incentives for combustion-based CHP systems in "levels 2 and 3" were not extended under *AB 2778* and reached a sunset at the end of 2007. However, Gov. Schwarzenegger indicated when he signed *AB 2778* that he expected additional legislative or PUC action to extend the incentives for other "clean combustion technologies like microturbines" (see Appendix C). There are efforts underway to develop a revised incentive program that would restore some level of support for all CHP that can meet minimum efficiency criteria, and continue to reward the use of renewable fuels regardless of technology type, but this is not yet in place.

Table ES-2: California Public Utilities Commission Self-Generation Incentive Program

Incentive Level	Eligible Technology	Current Incentive	*Previous Incentive (ca. 2007)*	System Size Range[1]
Level 1	Solar photovoltaics	Now under CSI program	*$2.50/Watt*	30 kW – 5.0 MW
Level 2	Wind turbines	$1.50/Watt	*$1.50/Watt*	30 kW – 5.0 MW
	Fuel cells (renewable fuel)	$4.50/Watt	*$4.50/Watt*	30 kW – 5.0 MW
	Microturbines and small gas turbines (renewable fuel)	None	*$1.30/Watt*	None – 5.0 MW
	Internal combustion engines and large gas turbines (renewable fuel)	None	*$1.00/Watt*	None – 5.0 MW
Level 3[2]	Fuel cells	$2.50/Watt	*$2.50/Watt*	None – 5.0 MW
	Microturbines and small gas turbines[3]	None	*$0.80/Watt*	None – 5.0 MW
	Internal combustion engines and large gas turbines[3]	None	*$0.60/Watt*	None – 5.0 MW

Source: California Center for Sustainable Energy, 2008

Notes:

"Small gas turbines" are gas turbines of 1 MW or less.

[1]Maximum incentive payout is capped at 1 MW, but systems of up to 5 MW qualify for the incentive. A recent revision in 2008 has allowed systems of 1-2 MW to receive 50% of the full incentive level and systems of 2-3 MW to receive 25% of the full incentive level.

[2]Level 3 technologies must utilize waste heat recovery systems that meet Public Utilities Code 218.5.

[3]These technologies must meet *AB 1685* emissions standards.

More recently, the landmark "Global Warming Solutions Act" enacted by *Assembly Bill 32*, may help to encourage the development of CHP as a greenhouse gas emission reduction measure. The California Air Resources Board, Energy Commission, and Public Utilities Commission have targeted 4 GW of additional CHP capacity in California by 2020, as an "early action" to meet the mandated reduction in year 2020 levels to benchmark 1990 levels (an effective 25% reduction compared with a business-as-usual situation).

Because CHP makes more efficient use of natural gas, and also can run on biogas where this is a natural methane source (e.g., dairy farm, landfill, wastewater treatment plant, etc.), significant carbon emission reductions are possible. For example, as shown in Figure 6, the Electric Power Research Institute (EPRI) calculates that a 300 kW CHP system could provide an annual reduction of 778 tons of carbon dioxide, relative to natural gas fired central generation. A 5 MW

CHP system for a major hotel/casino could potentially have emission reductions of about 13,000 tons per year, or almost 400,000 tons over a 30-year project life.

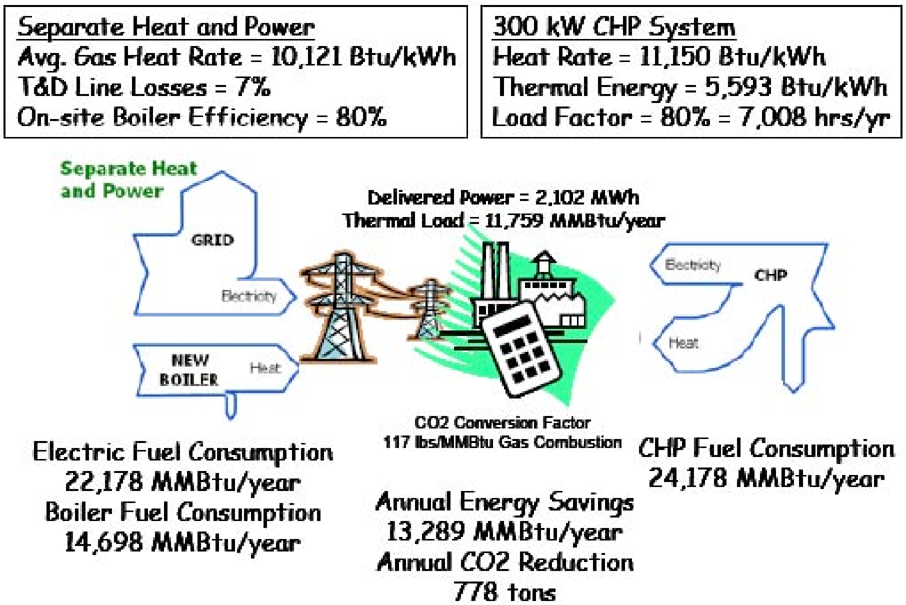


Figure ES-2: Estimate of the Carbon Reduction Benefits from CHP Systems
(Source: EPRI, 2005)

Additional CHP policy issues, including emission regulations, utility tariff structures, greenhouse gas emission regulations, net metering policies, and recently introduced legislative measures, are discussed in Section 6 of the main text of this report.

The Market Potential of CHP Systems in California

The remaining market potential of CHP systems in California has been estimated by EPRI in a recent study sponsored by the Commission. The study reports a total "technical" CHP capacity of over 14 GW for "traditional" CHP markets through 2020, or more than 25% of current total generating capacity in the state, and up to 30 GW when all potential is considered (including potential electricity export and cooling applications). However, the study finds that the "economic" potential is considerably lower based on various assumptions (EPRI, 2005).

Table ES-3, below, presents the key results of the EPRI (2005) analysis. Various future market scenarios are considered, with installation potential estimated to range from 1,141 MW to 7,340 MW. A "status quo" base case, with continuation of existing conditions, is assessed with an estimate of about 2 GW of additional CHP capacity. The estimates are strongly dependent on the nature of incentives and on the pace of technology improvement.

Table ES-3: California CHP Market Potential Estimates for 2005-2020

Scenario	Onsite CHP (MW)	Export CHP (MW)	Total Market Penetration (MW)	Description
Base Case	1,966	0	1,966	Expected future conditions with existing incentives
No Incentives	1,141	0	1,141	Remove SGIP, CHP incentive gas price, and CHP CRS exemptions
Moderate Market Access	1,966	2,410	4,376	Facilitate wholesale generation export
Aggressive Market Access	2,479	2,869	5,348	$40/kW year T&D capacity payments for projects under 20 MW, global warming incentive, and wholesale export
Increased (Alternative) Incentives	2,942	0	2,942	Extended SGIP (incentives on first 5 MW for projects less than 20 MW), $0.01/kWh CHP production tax credit
Streamlining	2,489	0	2,489	Customer behavior changes: higher response to payback levels and greater share of market that will consider CHP
High R&D on Base Case	2,764	0	2,764	Rate of technology improvement accelerated 5 years
High Deployment Case	4,471	2,869	7,340	Accelerated technology improvement with aggressive market access and streamlining to improve customer attitudes and response

Source: EPRI, 2005

Summary of CHP System Financial Assistance Programs

In addition to the SGIP program that is discussed in the previous section, that provides a direct capital cost buy-down for qualifying CHP systems, there are additional financial assistance programs available for CHP system installation in California. These include federal tax programs, low interest loan programs for small businesses, and CHP project screening services that are available on a limited basis from the PRAC and the U.S. Environmental Protection Agency. These programs are discussed in Section 8 of the main text of this report.

Action Plan for Advancing the CHP Market in California

The final section of this report presents a series of ideas for further advancing the CHP market in California. Key recommendations include:

1. Issue CPUC policy directives to utilities to require existing utility contracts for large "qualifying facility" CHP projects to be expeditiously extended.
2. Enact *AB 2778* "clean up" legislation that provides for continued SGIP capital cost support for fossil fuel-based CHP that complies with current best-available control technology (BACT) or CARB certification requirements. Examine combinations of capital cost and performance-based financial support schemes that may be more economically efficient than the simple ($/W) cost buy-down

type and revise program accordingly (e.g. following analogous changes in the California Solar Initiative program).

3. Institute co-metering for CHP systems to allow for power export to the grid with rules for power purchase from CHP system owners based on wholesale power prices plus consideration for their T&D, grid support (ancillary services), and GHG reduction benefits.
4. Encourage the use of CHP as a power reliability measure, in combination with standby gensets and other advanced storage technologies, for critical need applications such as refineries, water pumping stations, emergency response data centers, etc.
5. Per the Energy Commission IEPR, provide a unique position in the utility loading order for CHP projects to encourage them based on their energy efficiency and GHG reduction benefits.
6. Explore options for expanded use of renewable biogas in conjunction with onsite power generation through CHP, including the possibility of "wheeling" biogas through utility gas pipelines for use in CHP in other locations.
7. In accordance with *AB 32* for GHG reductions in California, develop a GHG credit scheme for CHP systems that could be used in the context of GHG emissions reduction credit trading systems.
8. Consider efforts to harmonize local air district emissions permitting and certification procedures within California, so that manufacturers do not face a complicated "mosaic" of different air quality regulations throughout the state and have fewer set of standards to meet.
9. Also per the Energy Commission IEPR, the CPUC should direct utilities to make capacity payments for the transmission and distribution benefits of CHP systems. Along with this, the CPUC and the Energy Commission should coordinate efforts with the utilities to develop and implement planning models to determine where in utility grids DG/CHP systems, whether in the singular or aggregate, would be most beneficial in terms of the transmission and distribution benefits.
10. Urge CPUC direction to the major California utilities, per *SB 28*, to develop more consistent and favorable utility tariff structure for CHP customers.

See Section 9 of the main text of this report for further elaboration of these "action plan" concepts.

<u>Conclusions</u>

In conclusion, California has historically been one of the most attractive states in the U.S. for CHP because of the combination of high electricity prices and favorable DG/CHP interconnection and incentive policies. California's stringent new DG air quality regulations, coupled with the recent lapse in SGIP incentive funds for most CHP technologies, pose a challenge for CHP system installation at the present time. However, several small fuel cell and microturbine systems have already certified to the 2007 ARB emission limits. Furthermore, some sites, particular with large thermal and/or "premium power" needs, may still find attractive economics to installing CHP in California. Larger CHP systems that are individually permitted require BACT systems for emission control, which creates a heavy financial burden for medium-sized systems in the 1-5 MW range.

In this context, California is currently at a crossroads with regard to the future CHP market. If the existing legacy systems that are nearing the end of their design lives can be re-powered and/or re-permitted, and supportive incentive and other policies can be maintained, we believe that the California CHP market can continue to expand even with the new more stringent air pollutant emission limits. However, if supportive policies are not further developed, to both encourage energy efficiency and to help meet the goals of California's *AB 32* greenhouse gas law, CHP market development in the state is likely to be seriously challenged.

1. Introduction

The purpose of this report is to provide an updated assessment and summary of the current status of combined heat and power (CHP) in California and to identify the hurdles that prevent the expanded use of CHP systems. This report has been prepared by the Pacific Region CHP Application Center (PRAC). The PRAC is a United States Department of Energy (DOE) and California Energy Commission[4] sponsored center to provide education and outreach assistance for CHP in the Pacific region of California, Nevada, and Hawaii. The PRAC is operated by the University of California – Berkeley (UCB), the University of California – Irvine (UCI), and San Diego State University (SDSU).

The information presented in this report is intended to provide:

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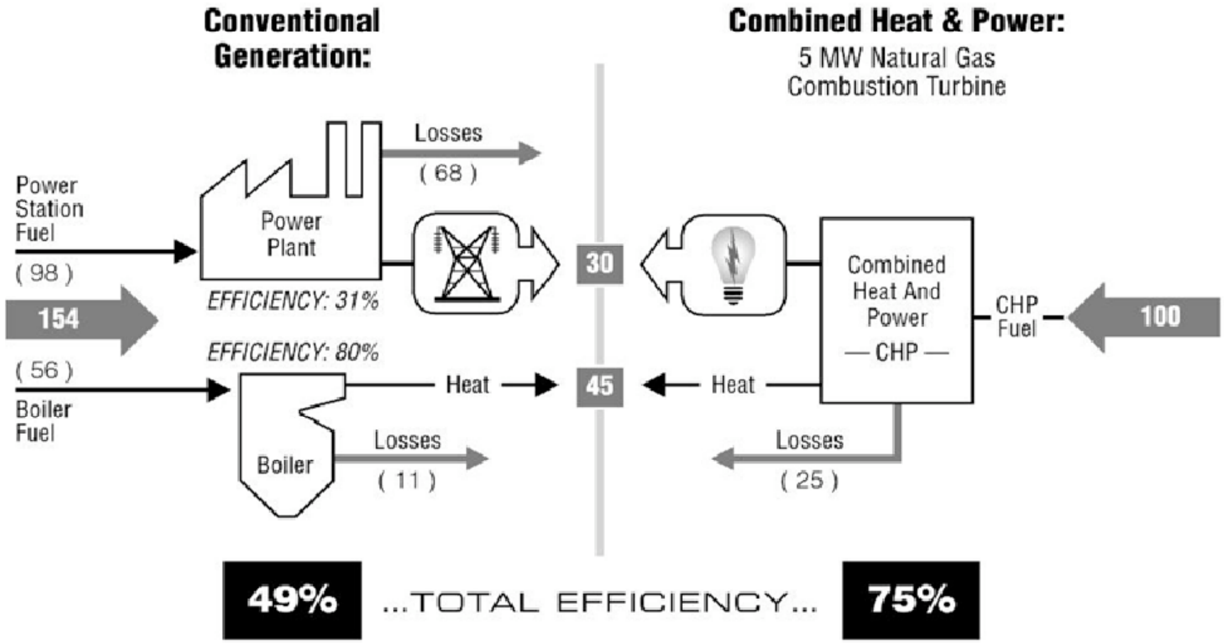
- a summary of the utility interconnection and policy environment for CHP in California;
- an assessment of the remaining market potential for CHP systems in California;
- an "action plan" to further promote CHP as a strategy for improving energy efficiency and reducing emissions from California's energy system; and
- an appendix of contacts for key organizations involved in the California CHP market.

As a general introduction, CHP is the concept of producing electrical power onsite at industrial, commercial, and residential settings while at the same time capturing and using waste heat from electricity production for beneficial purposes. CHP is a form of distributed generation (DG) that offers the potential for highly efficient use of fuel (much more efficient than current central station power generation) and concomitant reduction of pollutants and greenhouse gases. CHP can also consist of producing electricity from waste heat or a waste fuel from industrial processes.

The following figures depict the manner in which CHP systems can provide the same energy services as separate electrical and thermal systems, with significantly less energy input. As shown in Figure 1, to provide 30 units of electricity and 45 units of heat using conventional generation would require energy input of 154 units. A typical CHP system using a 5 MW combustion turbine could provide these same energy services with only 100 units of energy input, thereby saving net energy, cost, and greenhouse gas emissions.

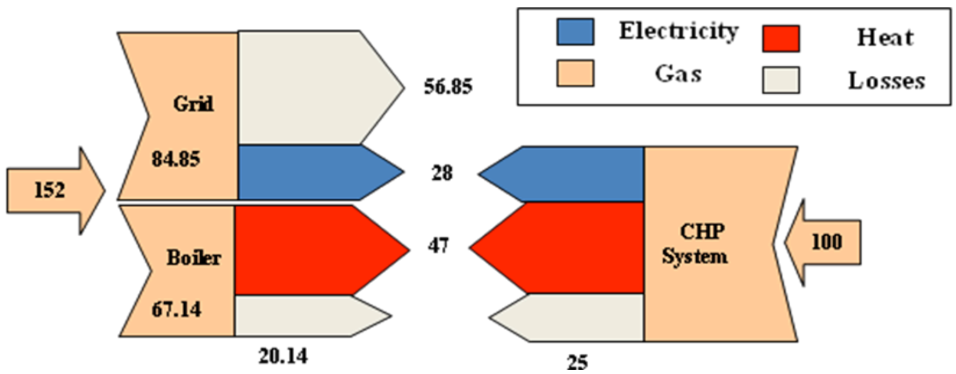
[4] Hereafter, the California Energy Commission is referred to as "the Energy Commission."



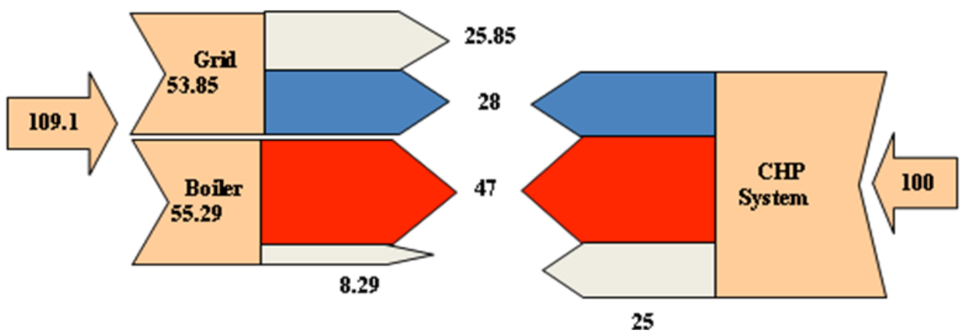
Source: Hedman, 2006

Figure 1: CHP Flow Diagram Based on 5 MW Combustion Turbine (generic energy units)

Figure 2 shows a more generalized depiction of the same concept. Compared with typical conventional generation, a present-day CHP system could provide the same electrical and thermal energy services with approximately two-thirds of the energy input. Even compared with a much advanced and more efficient combination of utility grid power and boiler technology in the future, the CHP system can still compete favorably. And of course the efficiencies of CHP "prime mover" technologies are also expected to improve over time.



Typical Conventional Generation



Advanced Technology for Grid and Boiler Technology

Figure 2: Generic CHP Flow Diagrams Compared with Typical and Advanced Conventional Generating Systems (generic energy units)

In addition to improving energy efficiency by capturing waste heat for thermal energy uses, CHP systems eliminate transmission and distribution (T&D) losses inherent in power produced from conventional centralized generation. These T&D losses are typically in the range of 7-11% of the amount of power delivered (Borbely and Kreider, 2001). CHP systems can also provide important grid "ancillary services" such as local voltage and frequency support and reactive power correction (i.e. "VARs"), and emergency backup power when coupled with additional electrical equipment to allow for power "islands" when the main utility grid fails.

Recognizing the potential of CHP to improve energy efficiency in the U.S., the DOE established a "CHP Challenge" goal of doubling CHP capacity from 46 GW in 1998 to 92 GW by 2010 (U.S. CHPA, 2001). As of 2006, there were an estimated 83 GW of CHP installed at 3,168 sites in the U.S., representing about 9% of total generating capacity in the country (Bautista et al., 2006). This suggests that the nation is generally on track to meet the DOE goal of 92 GW by 2010. However, new capacity additions appear to have slowed in recent years, with less than 2 GW installed in 2005 compared with about 4 GW in 2003 and 2004, and over 6 GW in 2001 (Bautista et al., 2006).

2. Report Purpose

As noted above, the purpose of this report is to assess the current status of combined heat and power (CHP) in California and to identify the hurdles that prevent the expanded use of CHP systems. The report summarizes the CHP "landscape" in California, including the current installed base of CHP systems, the potential future CHP market, and the status of key regulatory and policy issues. The report also suggests some key action areas to further expand the market penetration of CHP in California as an energy efficiency, cost containment, and environmental strategy for the state.

An additional purpose of the report is to alert stakeholders in California of the creation of the U.S. DOE "regional application centers" (or "RACs") for CHP. The PRAC serves the states of California, Hawaii, and Nevada by:

- providing CHP education and outreach services (e.g. with the PRAC website at http://www.chpcenterpr.org and through conferences and workshops);
- conducting "level 1" CHP project screenings for promising potential projects;
- developing CHP baseline assessment and action plan reports for each state in the region, to be periodically updated and improved; and
- developing example project profile "case studies" for CHP system projects in the Pacific region.

For the California CHP market specifically, the PRAC would like to work with CHP stakeholders and potential "end-users" in the state to further develop CHP resources for the state. California is a large and diverse state with special conditions and concerns related to its energy sector. The PRAC hopes to work with various groups in the state to develop energy strategies for California that are technically and economically sound, and also appropriate for California's environmental concerns.

3. The California CHP Landscape

California currently has approximately 9 GW of installed CHP capacity, or 17% of total electricity generating capacity in the state.[5] Much of this capacity is in the form of relatively large systems (i.e., greater than 20 MW), with systems smaller than 20 MW accounting for only about 10% of the total capacity. About half of the total CHP capacity (4,400 MW) is in the form of combustion turbines, with about a third (3,200 MW) in combined-cycle plants, about 900 MW in steam turbines, about 200 MW in reciprocating engines, and a few MW each for fuel cells and microturbines (Energy Commission, 2005). Estimates of the further market potential of CHP in California are discussed in Section 6, below.

Key organizations for the Pacific region CHP market include equipment suppliers and vendors, engineering and design firms, energy service companies, electric and gas utility companies (both "investor owned" and "municipal"), research organizations, government agencies, and other non-governmental organizations. Appendix D of this report includes a database of contact information for key organizations involved in the CHP market. The organizations listed in the appendix are those that have responded to requests for contact information. As subsequent revisions of this report are made, the PRAC expects the contact database to become more

[5] Consistent with typical reporting, the capacity indicated herein reflects electrical generation only.

complete and comprehensive.

California's electrical and natural gas services are provided by investor-owned utility companies (known as "IOUs"), municipal power organizations, and rural cooperatives. The major IOUs include Pacific Gas and Electric Company (PG&E), Southern California Edison (SCE), and the Sempra Group utilities of Southern California Gas Company (SoCal Gas) and San Diego Gas and Electric Company (SDG&E). Figure 3, below, shows the service territories of the main electrical utilities in California.

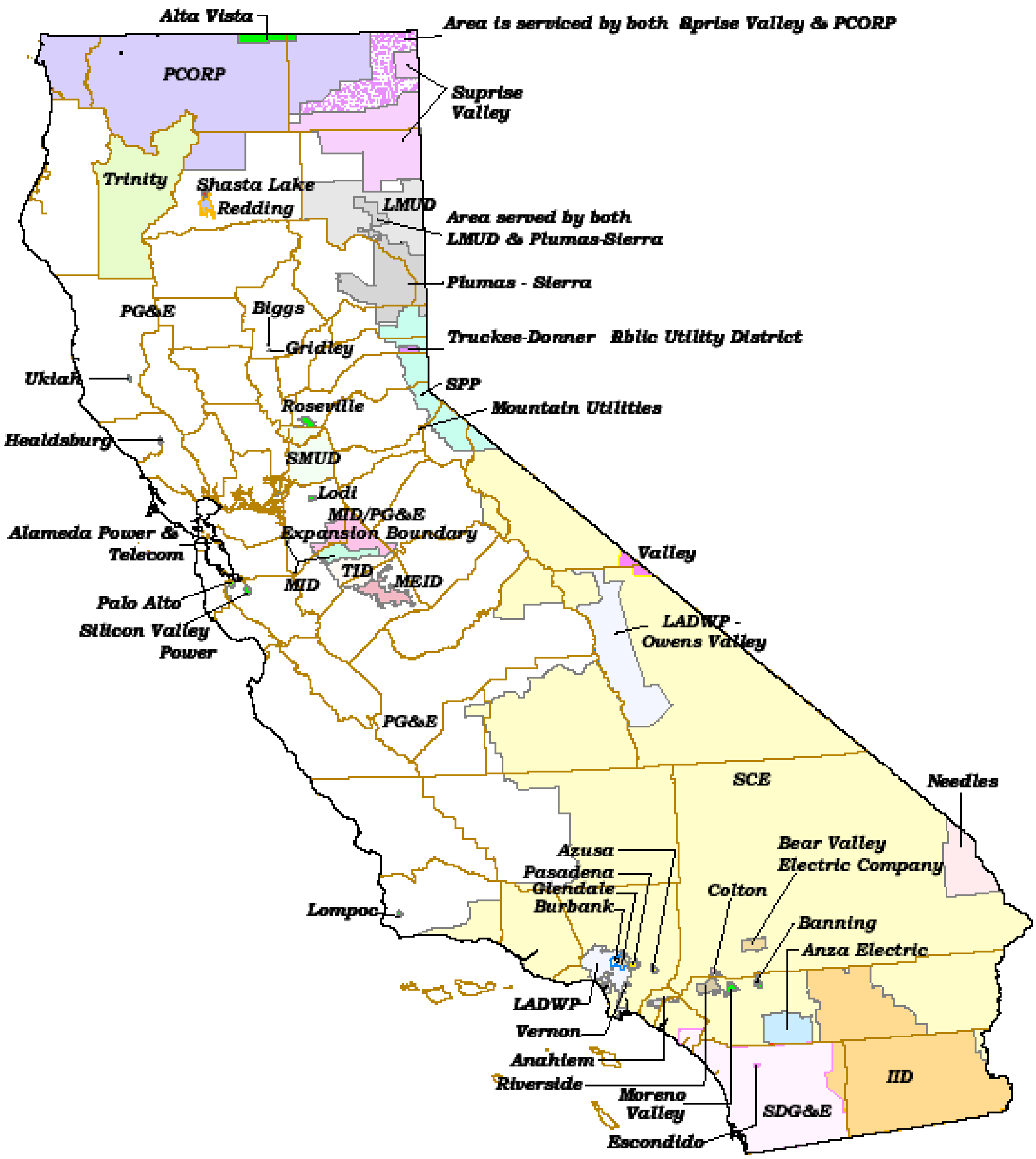


Figure 3: California Electric Utility Service Territories

4. Overview of CHP Installations in California

The Pacific region has several hundred 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. (EEA) database of CHP installations in the state shows a total of 947 sites. This total is not exactly correct because some of the older installations in the database may not be currently operational, and because the database is not comprehensive with regard to new installations. PRAC is working with EEA to update the database and improve its accuracy.

Table 1 shows a breakdown of the CHP sites by Pacific region state, along with additional data for the overall electricity generation in each state. California currently has approximately 9 GW of CHP capacity, with over 500 MW in Hawaii and 300 MW in Nevada. The average capacity of Pacific region CHP installations is 10.7 MW, and 55% of the CHP capacity is in large industrial systems of 50 MW or greater (Hedman, 2006). CHP systems in the western states of California, Hawaii, Nevada, and Arizona are estimated to be saving more than 370 trillion BTUs of fuel and 50 billion tons of CO_2 emissions per year, compared with the conventional generation they have replaced (Hedman, 2006).

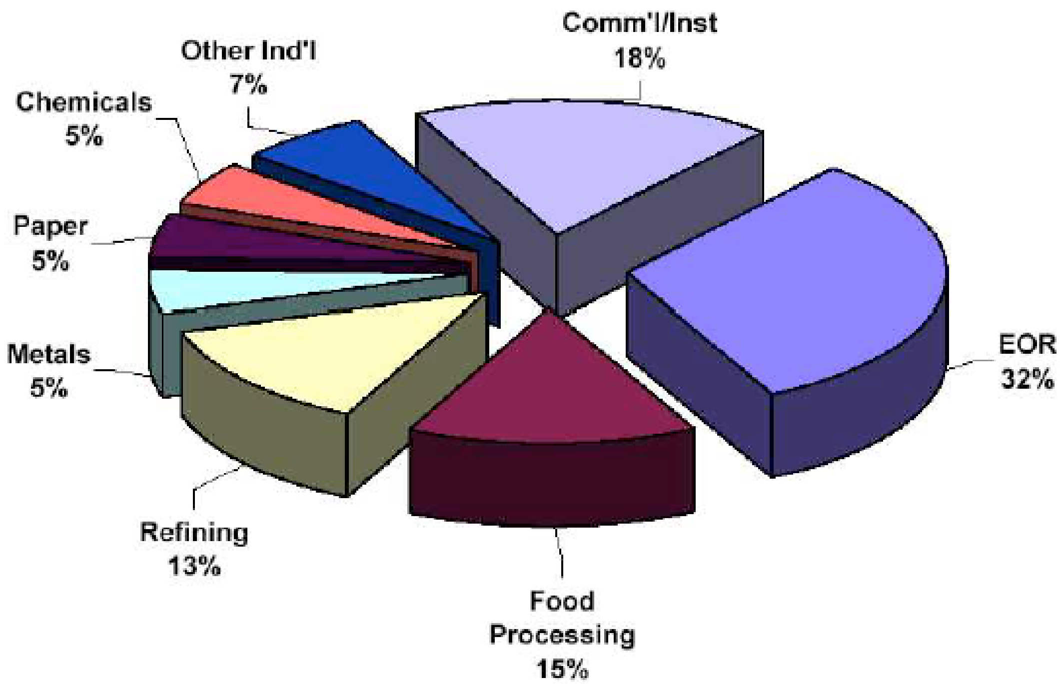
Table 1: Electricity Generating Capacity and CHP Installations in the Pacific Region

	California	Hawaii	Nevada
Retail Customers (1000s)	13,623	435	981
Generating Capacity (MW)	56,663	2,267	6,856
Generation (Million MWh)	184	12	32
Retail Sales (Million MWh)	235	10	29
Active CHP (MW)	9,121	544	321
CHP Share of Total Capacity	16.1%	24.0%	4.7%

Source: Hedman, 2006, based mostly on data from EIA, 2002

Figure 4, below, presents the composition of active CHP systems in California by application. As shown in the figure, about one-third of CHP in California is used in the context of enhanced oil recovery operations. The commercial/institutional sector accounts for 18%, food processing 15%, and oil refining 13%, with smaller contributions from other industrial sectors.

Figure 4: Composition of Active CHP Systems in California by Application



Source: Energy Commission, 2005a
Note: EOR is enhanced oil recovery

5. Technical and Economic Status of Key CHP Technologies

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 2 below presents key characteristics of each of these types of generators.

Table 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 85% (AE)	Up to 75% (AE)	Up to 75% (AE)	Up to 75% (AE)	Up to 90% (AE)
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 (GTI)	$0.007-0.015/kWh (GTI)	$0.005-0.01/kWh
Maintenance Interval	5,000-8,000 hrs	ID	40,000 hours	ID	ID

Source: Data from Energy Commission, 2007, except Gas Tech. Institute for O&M costs as noted by "GTI" and "AE" for author estimates

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.

For more details on characteristics of specific fuel cell technologies, see: http://www.energy.ca.gov/distgen/equipment/fuel_cells/fuel_cells.html.

Additional CHP system equipment includes electrical controls, switchgear, heat recovery systems, and piping for integration with building HVAC systems. Waste heat can be used to assist boilers to raise steam for building heating systems, to directly provide space heating or heat (or steam) for industrial processes, and/or to drive absorption or adsorption chillers to provide cooling.

In general, the economic conditions for CHP in California are aided by relatively high prevailing electricity prices and the presence of favorable capital cost buy-down incentives, but hindered by relatively high natural gas prices and relatively strict air quality regulations. California's economic incentives and air pollution emissions regulations are discussed in some detail in Section 6, below.

6. Summary and Status of CHP Policy Issues in California

Important policy issues for CHP include utility interconnection procedures, utility rate structures including "standby charges" and "exit fees," and economic incentive measures. Furthermore, the role of CHP in California's energy future has recently been highlighted in the latest Integrated Energy Policy Report (IEPR) produced by the Energy Commission. An overview of these CHP/DG policy areas for the California market is provided below.

California Integrated Energy Policy Report

The Energy Commission is required by California statute (under SB 1389) to produce a biennial "Integrated Energy Policy Report" (IEPR). The latest IEPR – the 2007 edition –was released in February, 2008 (Energy Commission, 2008). The previous 2005 edition, which addressed CHP in more detail, was released in November 2005 (Energy Commission, 2005). The report makes numerous references to the role of CHP in helping to provide energy resources for California's energy needs in an environmentally responsible manner. Following is a summary of the key statements in the IEPR related to the role of CHP.

The 2007 IEPR builds on the previous IEPR efforts, including the 2005 IEPR that had a more extensive discussion of the policy setting and challenges confronting further expansion of the CHP market in California. The 2007 IEPR's summary statement on CHP is as follows:

> "Distributed generation and combined heat and power, regardless of size or interconnection voltage, are valuable resource options for California. Combined heat and power, in particular, offers low levels of greenhouse gas emissions for electricity generation, taking advantage of fuel that is already being used for other purposes. Distributed generation can also play an important role in helping to meet local capacity requirements." (Energy Commission, 2008, p. 7)

The 2007 IEPR also notes that *AB 1613* was passed in October of 2007 *allows* the CPUC to require that utilities purchase excess generation from CHP systems size at 20 MW or less. However, as noted in the IEPR, *AB 1613* does not *compel* the CPUC to do this (Energy Commission, 2008). As of yet, this has not been done, but the CPUC is apparently considering what if any new rules to impose.

With regard to advancing the development of CHP as an energy efficiency and GHG reduction strategy, the 2007 IEPR recommends that:

- SGIP incentives should be based on overall efficiency and performance of systems, regardless of fuel type;
- the CPUC should complete a tariff structure to make CHP projects "cost and revenue neutral" while granting system owners credit for grid benefits;
- the CPUC and the Energy Commission should cooperate to eliminate all non-bypassable charges for CHP and DG;

- efforts be continued to improve the Rule 21 process to streamline interconnection and permitting;

- either a CPUC procurement portfolio standard should be developed for CHP, for electric utility procurement plans, or require utilities to treat DG and CHP like they are required to treat efficiency programs;

- the CPUC should adopt revenue neutral programs to make high-efficiency CHP able to export power to interconnected utilities;

- efforts should continue to estimate CHP system costs and benefits; and

- the state should adopt GHG policy measures that reflect the benefits that CHP can provide in reducing GHG emissions compared with separate provision of electric and thermal energy.

Going back a few years, the 2005 IEPR also called out the role of CHP in California, and went into more detail with regard to existing barriers and potential future policy and regulatory development. One summary paragraph reads as follows:

> "Cogeneration, or combined heat and power (CHP), is the most efficient and cost-effective form of DG, providing numerous benefits to California including reduced energy costs, more efficient fuel use, fewer environmental impacts, improved reliability and power quality, locations near load centers, and support of utility transmission and distribution systems. In this sense, CHP can be considered a viable end-use efficiency strategy for California businesses. There are more than 770 active CHP projects in California totaling 9,000 MW, with nearly 90 percent of this capacity from systems greater than 20 MW. CHP has significant market potential, as high as 5,400 MW, despite high natural gas prices." (Energy Commission, 2005, p. 76)

The 2005 IEPR further highlighted the role of CHP at petroleum refineries, to make them less vulnerable to power outages. The report notes the important economic and environmental impacts that resulted from a power outage on September 12, 2005 in Southern California that forced the shutdown of three refineries in the Wilmington area (Energy Commission, 2005).

The 2005 IEPR noted that much of California's CHP capacity is in the form of relatively large systems, while smaller systems have been the focus of most recent policy efforts. CHP systems smaller than 20 MW represent less than 10% of total CHP capacity and systems smaller than 5 MW represent only about 3% of the total CHP capacity (Energy Commission, 2005). This shows that larger systems can provide more "bang for the buck" in adding capacity,[6] but also could indicate significant under-realized potential for further installations of smaller CHP systems.

The 2005 IEPR went on to note that much of the CHP currently operational in California was installed under utility contracts that were put in place in the 1980s. Unless these contracts can be renewed, and some problems in this regard are noted in the report, the state could see as much as 2,000 MW of currently operational CHP become shut down by 2010 (Energy Commission, 2005).

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[6] However, we note that on a per-MW basis, smaller CHP systems can typically provide greater benefits to utility grids than larger systems due to their inherently more dispersed nature.

The 2005 IEPR then addressed the important issue of the interaction between CHP systems and utility grids, noting the difficulty of optimally sizing CHP systems given the barriers associated with exporting excess power:

> "CHP developers seeking to install new generation are presently discouraged from sizing their systems to satisfy their full thermal loads because they would have to generate more electricity than they could use on site. These developers frequently have trouble finding customers interested in buying their excess power at wholesale prices. Lack of a robust, functioning wholesale market in California worsens CHP concerns about this risk. Even if wholesale markets were functioning well, CHP owners would still struggle with the complexity and cost of complying with the CA ISO's tariff requirements, including scheduling exports hour-by-hour, installing costly metering and reporting equipment, and other factors." (Energy Commission, 2005, p. 77)

The most noteworthy conclusion of the 2005 IEPR with regard to CHP was that given the unique benefits that it can offer, CHP deserves its own unique place in the "loading order" for utility grids. The 2005 IEPR recommended that the CAISO modify its tariff structure for CHP systems so that these systems can sell power into the system at reasonable prices, and also recommends that utilities should be required to offer CAISO scheduling services at cost (i.e. without markup) to their CHP customers. The 2005 IEPR also recommended that CHP be separated from other DG in the next version of the CPUC's Energy Action Plan so that the special issues and barriers faced by CHP can be examined specifically, without being lost in the overall picture of broader DG policy and regulatory issues (Energy Commission, 2005).

Grid Access and Interconnection Rules

California has made major progress in recent years with regard to DG grid interconnection with the development of a revised "Rule 21" interconnection standard. The revised Rule 21 is the result of a CPUC order (rulemaking 99-10-025) in October 1999 to address DG interconnection standards. Based on this order, the Energy Commission issued a technical support contract in November 1999 known as FOCUS (Forging a Consensus on Utility Systems) to develop a new interconnection standard for the state (Energy Commission, 2007).

With representatives from the CPUC, the Energy Commission, and the state's electric utilities, a working group was formed through the FOCUS contract to revise Rule 21. The CPUC approved the revised rule on December 21, 2000. The major IOUs in the state then adopted the new rule by instituting the *Rule 21 Model Tariff, Interconnection Application Form, and Interconnection Agreement* (Energy Commission, 2007).

The key provisions of the revised Rule 21 are:

- the IOUs must allow interconnection of generating facilities within their distribution systems, subject to compliance with the Rule 21 provisions;

- generating facilities that are interconnected must meet the IEEE 1547 requirements for DG interconnection;[7]

- the IOUs have the right to review generation and interconnection facility designs

[7] American National Standards Institute/Institute of Electrical and Electronic Engineers (ANSI/IEEE) 1547-2003 "Standards for Interconnecting Distributed Resources with Electric Power Systems."

and to require modifications to comply with Rule 21 provisions, as well as to access generation/interconnection facilities to perform essential duties; and

- the IOUs may limit the operation of a generating facility, or disconnect it, during times of emergency or in the case of unsafe operating conditions.

In addition, Rule 21 prescribes a timeline for the interconnection application process so interconnection agreements proceed in a timely fashion. This timeline is as follows:

- within 10 days after receipt of an interconnection application the utility will acknowledge receipt of the application and indicate if it has/has not been adequately completed;
- within 10 days of determination of a complete application, the utility will complete its initial review, and either: 1) supply an Interconnection Agreement for the applicant's signature if the utility determines that a Simplified Interconnection will be adequate; or 2) notify the applicant and perform a Supplemental Review if deemed necessary (and if so complete the Supplemental Review within 20 days of receiving the application and any required fees);
- if a Supplemental Review is necessary, the utility will provide an agreement that outlines the utility's schedule and charges for completing the additional review (systems that qualify for net metering, such as solar facilities, are exempt from interconnection study fees).

The Energy Commission has compiled statistics on utility interconnection activities under Rule 21, starting in 2001 and running through June of 2006, for the three major IOUs in California. These statistics are presented in Table A-1 in Appendix A.

However, despite the progress made through the development of the Rule 21 process, significant barriers remain for CHP systems in California with regard to grid interconnection. Perhaps most importantly, CHP system developers have difficulty selling excess power to other utility customers at wholesale prices due to difficulties with utility contracts, and the complexity and cost of complying with CAISO tariff requirements for scheduling, metering, and reporting (Energy Commission, 2005). Furthermore, the *Public Utilities Code Section 218* creates additional barriers by barring the direct transmission of excess utility to nearby facilities across public roads.

<u>Utility Rates, Standby Charges, and Exit Fees</u>
A general issue for the development of CHP is the incentive structure for IOUs and other electric utility companies. These firms earn guaranteed but regulated rates of return on capital assets, in return for a geographic monopoly in the ownership of electricity generation assets, with some exceptions. Within this structure, existing or potentially attractive future CHP installations represent opportunities for guaranteed profitable investments that have been forgone. For this reason, CHP developers often believe that IOUs adopt rules and tariffs that discriminate against CHP projects. Important among these are "standby charges" that require CHP system owners to pay for utility services that they rarely need. IOUs tend to deny these allegations, with arguments that attempt to rationalize their rates and incentive structures. This is an ongoing topic of significant importance to CHP markets that deserves further research.

Facilities with customer-owned generation systems are typically offered a specific utility tariff schedule that complies with the relevant CPUC guidelines. These include rules for the extent to which DG/CHP customers are required to pay bond charges, competitive transition charges and so on. The first few pages of example rate schedule for a DG customer, for the Pacific Gas and Electric service territory, is included in Appendix B. This is the "Schedule E" tariff, for "Departing Customer Generation."

One controversial issue for DG/CHP systems is the extent to which they are required to pay "exit" or "departing load" fees when they come online. Under a decision announced by the CPUC on April 3, 2003 (*Decision 03-04-030*), customers that partially or fully provide their own generation may be exempt from exit fees under certain conditions. The rules are as follows (Energy Commission, 2007c):

- Systems smaller than 1 MW that are net metered and/or eligible for CPUC or Energy Commission incentives for being clean and super clean are fully exempt from any surcharge; including solar, wind, and fuel cells.

- Biogas customers eligible under *AB 2228* are also exempt from surcharges.

- Ultra-clean and low-emission systems 1 MW or greater that meet Senate Bill 1038 requirements to comply with CARB 2007 air emission standards will pay 100% of the bond charge, but no future DWR charges or utility under-collection surcharges.

- All other customers will pay all components of the surcharge except the DWR ongoing power charges. When the combined total of installed generation reaches 3,000 MW (1,500 designated for renewables), any additional customer generation installed will pay all surcharges.

The Energy Commission has been tasked with determining the eligibility for these exit fee exemptions. The Energy Commission also tracks the installation of DG systems subject to the 3,000 MW cap, with set asides of 1,500 MW for renewables and allocation of the other 1,500 MW as follows: 600 MW by 2004; 500 MW by July of 2008, and 400 MW thereafter. The UC/CSU system also receives a specific set-aside within the caps of 10 MW by 2004; 80 MW by 2008, and 75 MW thereafter (Tomashefsky, 2003).

Another controversial issue is that each of the California IOUs has PUC-approved "cogeneration deferral rate" that allows them to offer a customer a discounted rate if they forego a viable CHP project. In order to obtain these reduced rates, the customer must demonstrate that a proposed CHP project is viable and then sign an affidavit that indicates that the acceptance of the deferral rate is the motivation for foregoing the project, and that the CHP system will not be installed during the term of the agreement. The existence of these rates effectively tips "the playing field" for CHP developers, making the installation of projects more difficult.

A recent analysis conducted for the Energy Commission by Competitive Energy Insight, Inc. examined various utility rates in California as they pertain to CHP customers. The key findings of this analysis are that (Competitive Energy Insight, 2006):

- utility rates for CHP customers are highly complex and vary considerably among the major California utilities, providing "inconsistent and difficult to interpret pricing signals to the CHP market;"

- there is a trend toward shifting cost recovery from energy rates to demand and standby rates, thus raising the importance of CHP system reliability/availability and flawless system performance to avoid demand and standby charges;

- SDG&E and PG&E rate structures offer relatively attractive economics for CHP under the right conditions, but the SCE rate structure is much less attractive for CHP applications due in part to low off-peak rates that reduce the economic attractiveness of CHP;

- exempting CHP projects of 1 MW and smaller from the DWR bond component of departing load charges creates an arbitrary breakpoint in the CHP incentive/disincentive cost structure; and

- the SGIP program is critical to the attractiveness of CHP economics in California.

The report concludes with various recommendations for improving the attractiveness of CHP installation from the customer's perspective by reforming utility rate making practices. Some of these recommendations are included in Section 9 of this report.

Market Incentives for CHP System Installation

California has historically had one of the most extensive incentive programs for DG system installation in the country. The primary program is the Public Utilities Commission Self-Generation Incentive Program (SGIP) that was created with *AB 970* in 2000. A second smaller program, targeted primarily at residential customers and smaller system sizes, is the Energy Commission's Emerging Renewables Program.[8]

Customers of the major IOUs in the state are eligible for the SGIP. The SGIP is administered by the IOUs under PUC oversight, with the exception of the San Diego area where the program is administered by the California Center for Sustainable Energy[9]. In 2006, incentive support for solar photovoltaics (PV) was separated out from the SGIP with the creation of the new California Solar Initiative (CSI). The CSI provides $2.2 billion in funding for solar PV in California over a ten year period through 2016. Under the CSI, larger PV systems (over 100 kW) will receive performance-based incentives for kWh produced, rather than the previous lump sum for system installation based on system size (Go Solar California, 2008).

Table 3, below, presents the current SGIP incentive levels and the most recent previous levels that were in effect through December 2007. *AB 2778*, signed by Gov. Schwarzenegger in September of 2006, extended the SGIP program through 2011 for wind and fuel cell technologies. Importantly, incentives for CHP systems in levels 2 and 3 were not extended under *AB 2778* and reached a sunset at the end of 2007. However, Gov. Schwarzenegger indicated when he signed *AB 2778* that he expected additional legislative or PUC action to extend the incentives for other "clean combustion technologies like microturbines." The Governor noted that if the legislature failed to act in this regard, the PUC does not require legislative action to extend the SGIP for CHP technologies past 2007. The complete signing statement by the Governor is included in Appendix C of this report.

[8] For details on the Emerging Renewables Program visit: http://www.consumerenergycenter.org/erprebate/index.html
[9] That California Center for Sustainable Energy is formerly known as the San Diego Regional Energy Office.

Table 3: California Public Utilities Commission Self-Generation Incentive Program

Incentive Level	Eligible Technology	Current Incentive	*Previous Incentive (ca. 2007)*	System Size Range[1]
Level 1	Solar photovoltaics	Now under CSI program	*$2.50/Watt*	30 kW – 5.0 MW
Level 2	Wind turbines	$1.50/Watt	*$1.50/Watt*	30 kW – 5.0 MW
	Fuel cells (renewable fuel)	$4.50/Watt	*$4.50/Watt*	30 kW – 5.0 MW
	Microturbines and small gas turbines (renewable fuel)	None	*$1.30/Watt*	None – 5.0 MW
	Internal combustion engines and large gas turbines (renewable fuel)	None	*$1.00/Watt*	None – 5.0 MW
Level 3[2]	Fuel cells	$2.50/Watt	*$2.50/Watt*	None – 5.0 MW
	Microturbines and small gas turbines[3]	None	*$0.80/Watt*	None – 5.0 MW
	Internal combustion engines and large gas turbines[3]	None	*$0.60/Watt*	None – 5.0 MW

Source: California Center for Sustainable Energy, 2008
Notes:
"Small gas turbines" are gas turbines of 1 MW or less.
[1]Maximum incentive payout is capped at 1 MW, but systems of up to 5 MW qualify for the incentive. A recent revision in 2008 has allowed systems of 1-2 MW to receive 50% of the full incentive level and systems of 2-3 MW to receive 25% of the full incentive level.
[2]Level 3 technologies must utilize waste heat recovery systems that meet Public Utilities Code 218.5.
[3]These technologies must meet *AB 1685* emissions standards.

Air Pollutant Emissions Regulations for DG/CHP in California

The California Air Resources Board (CARB) regulates stationary and mobile sources of air pollution in California. Under the requirements of *SB 1298*, ARB adopted a DG emissions certification program on November 15, 2001. Under this program, smaller DG units that are exempt from local permitting regulations are now required to certify to the 2007 emissions limits. Larger DG/CHP systems, including turbines and reciprocating engines, are individually permitted by local air districts.[10]

The permitting process for these larger systems typically requires the use of "Best Available Control Technology" (BACT). Under the current regulations for these larger systems, specific

[10] Rules vary somewhat by individual air district, so prospective installers should check on the local regulations that apply to their region.

BACT emissions levels for NOx, VOCs, and CO are specified for turbines of different sizes (less than 3 MW, 3-12 MW, and 12-50 MW) and simple versus combined cycle operation. For reciprocating engines, emission standards are specified for fossil fuel versus waste-fired operation (CARB, 2002).

The 2007 CARB emission limits are applicable as of January 1, 2007 for fossil fuel based systems and as of January 1, 2008 for waste gas based systems, for installations that can be pre-certified and are not required to be individually permitted. These emissions limits are presented in Table 4, below. As shown in the table, waste gas based systems are effectively "grandfathered in" to the limits with less stringent requirements in place until 2013, after which they have to meet the same requirements as fossil fuel based systems.

In particular, the new 0.07 lb/MW-hr NOx limit is very challenging for CHP system developers to meet, particularly for somewhat smaller systems in the 1-5 MW range, where the costs of emission control equipment can have a major impact on the overall economics of the project. An additional issue is the varying emission control permitting and certification procedures (and in some cases limits) imposed by various air pollution control districts in California, creating a complicated and confusing "mosaic" of different rules within the state for system manufacturers and developers to meet.

Table 4: 2007 CARB DG Emission Limits

Pollutant	**Fossil Fuel System Emission Lmits (lb/MW-hr)**	**Waste Gas System Emission Limits (lb/MW-hr)**	
Effective Date	Jan. 1, 2007	Jan. 1, 2008	Jan. 1, 2013
NOx	0.07	0.5	0.07
CO	0.10	6.0	0.10
VOCs	0.02	1.0	0.02

Source: CARB, 2006

As of early 2007, several fuel cell systems and one microturbine system have been certified under the 2007 CARB program. These certifications are shown in Table 5, below.

Table 5: Current CARB DG Emissions Certifications

Company Name	Technology	Standards Certified To	Executive Order	Expiration Date
United Technologies Corp. Fuel Cells	200 kW, Phosphoric Acid Fuel Cell	2007	DG-001-A	January 29, 2007
FuelCell Energy, Inc.	250 kW, DFC300A Fuel Cell	2007	DG-003	May 7, 2007
Plug Power Inc.	5 kW, GenSys^{TM} 5C Fuel Cell	2007	DG-006	July 16, 2008
FuelCell Energy, Inc.	1 MW, DFC1500 Fuel Cell	2007	DG-007	September 13, 2008
Ingersoll-Rand Energy Systems	250 kW, 250SM Microturbine	2007	DG-009	October 21, 2009
FuelCell Energy, Inc.	250 kW, DFC300MA Fuel Cell	2007	DG-010	December 16, 2009
FuelCell Energy, Inc.	300 kW, DFC300MA/C300 Fuel Cell	2007	DG-013	January 9, 2011

Source: CARB, 2007

Greenhouse Gas Emission Policy in California

In addition to stringent air pollutant emissions regulation, California has recently taken an aggressive policy stance to limit emissions of greenhouse gases (GHGs). The most dramatic policy measure is the passage of the *Global Warming Solutions Act* as *AB 32*, which seeks to limit GHG emissions from a wide range of industrial and commercial activities. *AB 32* requires that the state's emissions of GHG be reduced to 1990 levels by 2020 through an enforceable statewide cap, and in a manner that is phased in starting in 2012 under rules to be developed by CARB. This would amount to an approximate 25% reduction in emissions by 2020, compared with a business-as-usual scenario.

AB 32 requires that CARB use the following principles to implement the cap:

- distribute benefits and costs equitably;
- ensure that there are no direct, indirect, or cumulative increases in air pollution in local communities;
- protect entities that have reduced their emissions through actions prior to this regulatory mandate; and
- allow for coordination with other states and countries to reduce emissions.

CARB is required to produce a plan for regulations to meet the *AB 32* goals by January 1, 2009 and to adopt the regulations by January 1, 2011. The expectation is generally for a plan that includes a market-based emission credit-trading scheme under the statewide cap.

Because CHP makes more efficient use of natural gas, and also can run on biogas where this is a natural methane source (e.g., dairy farm, landfill, wastewater treatment plant, etc.), significant carbon emission reductions are possible. For example, as shown in Figure 5, the Electric Power Research Institute (EPRI) calculates that a 300 kW CHP system could provide an annual reduction of 778 tons of carbon dioxide, relative to natural gas fired central generation. A 5 MW CHP system for a major hotel/casino could potentially have emission reductions of about 13,000 tons per year, or almost 400,000 tons over a 30-year project life.

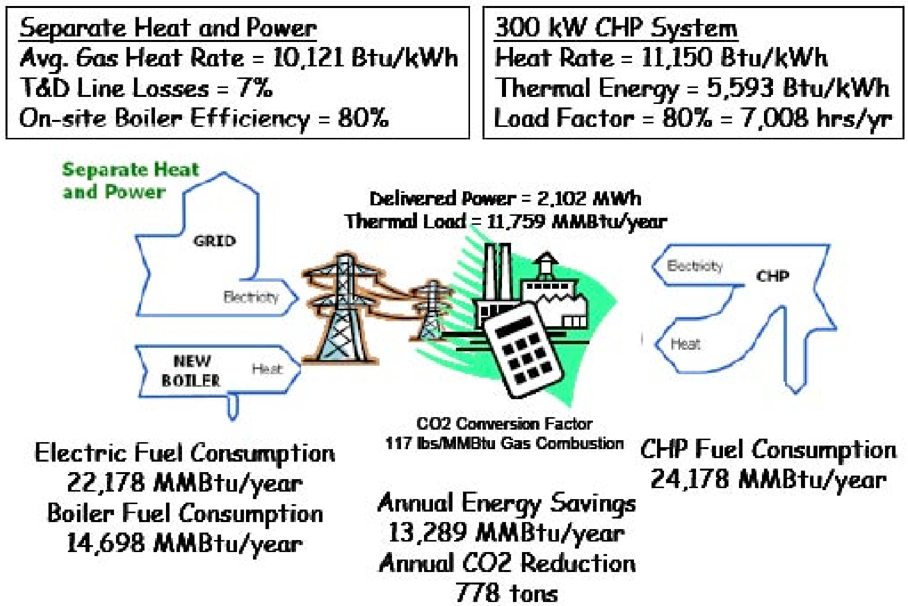

Figure 5: Estimate of the Carbon Reduction Benefits from CHP Systems
(Source: EPRI, 2005)

CHP systems can thus offer attractive GHG emissions reductions compared with more traditional central generation, and therefore have been identified as one strategy for helping to meet the *AB 32* goals. The Energy Commission and the CPUC have recently identified a goal of 4 GW of additional installed CHP capacity in California by 2020, in addition to the approximate 9 GW of currently installed capacity. A workshop was held in late August 2008, to identify barriers to achieving this goal. Several key barriers and potential policy actions were discussed, including allowing export of electricity from CHP plants to the local utility, re-instating SGIP incentives for all efficient CHP systems, providing better quantification of the GHG benefits that CHP systems can offer, and so on.

<u>California Net Metering Regulations</u>

California has had a "net metering" program since 1996. Net metering allows certain types of DG to be metered on a "net" basis where additions of power to the local utility grid are credited and offset against later power demands from the utility grid (typically up to 12 months). Net metering programs differ considerably from state to state, including the types of generators that are allowed to be net metered, size limitations, ability to combine net metering with time-of-use electricity rates, etc.

California's net metering program currently applies to solar, wind, biogas, and fuel cell generation systems. IOUs are required to offer net metering for all of these generator types, and municipal utilities are required to net meter solar and wind generation systems. Net metering is generally only available for systems of 1 MW or less in size, but a recent law (*AB 728* enacted in 2005) allows up to three larger biogas systems, of up to 10 MW each, to be net metered with a total statewide cap of 50 MW. The overall limit for net-metered systems in a utility service territory is now 2.5% of total customer peak demand (NC State University, 2007).

Of most relevance for CHP, fuel cell systems were added to the California net metering program in 2003. These systems are eligible for net metering regardless of the fuel source used, until the total installed base of net-metered fuel cells in a utility service territory reaches 45 MW (or 22.5 MW for utilities with a peak demand of 10 GW or less). As discussed above, systems that are eligible for net metering are exempt from exit fees, interconnection application fees, and any initial or supplemental interconnection review fees (NC State University, 2007).

California Renewable Portfolio Standard

A Renewable Portfolio Standard (RPS) measure was enacted in California in 2002 to require state IOUs to increase the level of renewable energy generated electricity that they purchase and sell, from approximately 11% in 2002 to 20% by 2017. The measure is primarily encouraging the development of utility scale wind and solar power projects, but other renewable power projects can also figure in to the RPS goals once certified by the Energy Commission. For example, biomass and other bio-energy could qualify for the RPS and also employ CHP to improve efficiency with suitable uses identified for heating and/or cooling nearby.

In the 2003 version of the IEPR, the Energy Commission recommended accelerating the goal to 2010 because of the perceived significant progress already made toward the 20 percent goal. The report also recommended developing more ambitious post-2010 goals to maintain the momentum for continued renewable energy development, expand investment and innovation in technology, and bring down costs (Energy Commission, 2003).

The 2004 IEPR Update recommended an increased goal of 33 percent renewable by 2020, arguing that IOUs with the greatest renewable potential should have a higher RPS target. Because SCE has three-fourths of the state's renewable technical potential and had already reached 17.04 percent renewable by 2002,155 the report recommended a new target for SCE of 35 percent by 2020 (Energy Commission, 2004). The report also recommended that municipal utilities be included in the RPS program, but this has been unsuccessful in the meantime.

Unfortunately, despite the early enthusiasm about progress under the RPS measure, statistics show that in 2004 California was powered by renewables for only 10.6% of its needs (Energy Commission, 2005). Renewables use thus increased proportionally with overall load growth from 2002 through 2004, but did not advance further to comply with the RPS goals. The 2007 IEPR includes recommendations for simplifying, streamlining, and strengthening the renewable energy effort in California, and notes the potential role of biomass in meeting the 2010 and beyond renewable energy goals (Energy Commission, 2008).

CHP System Owners as "Electrical Corporations" Under PUC Section 218

One important restriction for CHP in California arises from California Public Utilities Code 218.

This section prohibits power sales by "electrical corporations" across public streets or highways, greatly limiting the ability of DG/CHP system owners to provide power to additional sites other than the immediate one where the generating system is installed.

On February 24, 2006, Senator Kehoe introduced SB 1727 in order to address this limitation. SB 1727 would create an exception to the definition for what constitutes an "electrical corporation." The new exception would allow an entity with a generation facility specifically employing CHP, the use of landfill gas, or the use of digester gas technology to privately distribute the electricity across a public street or highway to an adjacent location, owned or controlled by the same entity, for its own use or use of its tenants, without becoming a public utility. As of early 2007, SB 1727 appears to have stalled in the legislature but may be taken up again later in the year.

Assembly Bill 1613: The Waste Heat and Carbon Emissions Reduction Act

In October 2007, Gov. Schwarzenegger signed Assembly Bill 1613 (*AB 1613 - Blakeslee*), co-authored by Assembly members Adams, Emmerson, Parra, and Torrico. This bill – the most significant bill for CHP introduced in recent years – should help to promote CHP as an energy efficiency and GHG reduction measure. The key provisions of the bill are to:

1) make waste heat recovery for electricity production and other useful purposes "energy efficiency" for purposes of the utility loading order;
2) establish as a goal the installation of 5,000 MW of new electrical generation by 2015 through the installation of CHP systems;
3) require load-serving entities to purchase, under conditions established by the PUC as just and reasonable, the incidental electricity produced by CHP systems that complies with regulations established by the Energy Commission;
4) establish a rate program by electric utilities for customers that install CHP systems and also have plug-in hybrid vehicles, to encourage charging of the vehicles during non-peak periods in ways that would also reduce GHG emissions in line with *AB 32* goals;
5) require the PUC, in consultation with the Energy Commission, to streamline and simplify interconnection rules and tariffs to reduce impediments to CHP system installation;
6) authorize load serving entities to receive credit for GHG emission reductions from electricity purchased from CHP systems;
7) require the PUC to report the legislature by the end of 2008 on a SGIP incentive formula that includes incentives for CHP systems that reduce emissions of GHGs;
8) establish state policy to reduce energy purchases for state owned buildings by 20% by December 31, 2015, through "cost effective, technologically feasible, and environmentally beneficial efficiency measures and distributed generation technologies."

AB 1613 is thus an ambitious piece of legislation that may help to foster the continued development of CHP in California. .

7. The Market Potential of CHP Systems in California

The remaining market potential of CHP systems in California has been estimated by the Electric Power Research Institute (EPRI) in a recent study sponsored by the Commission. The study reports a total "technical" CHP capacity of over 14 GW for "traditional" CHP markets through 2020, or more than 25% of current total generating capacity in the state, and up to 30 GW when all potential is considered (including potential electricity export and cooling applications). However, the study finds that the "economic" potential is considerably lower (see table below) based on various assumptions (EPRI, 2005).

In general, the remaining potential CHP capacity in California is judged to be rather different in character than the current installed CHP base. Approximately two-thirds of the remaining capacity is in the commercial/institutional sector, compared with a large amount of CHP currently installed in the industrial sector. Correspondingly, over 75% of the remaining capacity is estimated to be for systems of less than 5 MW in size. Much of the remaining capacity is in sectors with limited previous CHP experience (schools, hospitals, food processing, etc.) suggesting an important role for education and outreach activities to reach these sectors (Hedman, 2006; EPRI, 2005).

Table 6, below, presents the key results of the EPRI (2005) analysis. Various future market scenarios are considered, with installation potential estimated to range from 1,141 MW to 7,340 MW. A "status quo" base case, with continuation of existing conditions, is assessed with an estimate of about 2 GW of additional CHP capacity. The estimates are strongly dependent on the nature of incentives and on the pace of technology improvement.

Table 6: California CHP Market Potential Estimates for 2005-2020

Scenario	Onsite CHP (MW)	Export CHP (MW)	Total Market Penetration (MW)	Description
Base Case	1,966	0	1,966	Expected future conditions with existing incentives
No Incentives	1,141	0	1,141	Remove SGIP, CHP incentive gas price, and CHP CRS exemptions
Moderate Market Access	1,966	2,410	4,376	Facilitate wholesale generation export
Aggressive Market Access	2,479	2,869	5,348	$40/kW year T&D capacity payments for projects under 20 MW, global warming incentive, and wholesale export
Increased (Alternative) Incentives	2,942	0	2,942	Extended SGIP (incentives on first 5 MW for projects less than 20 MW), $0.01/kWh CHP production tax credit
Streamlining	2,489	0	2,489	Customer behavior changes: higher response to payback levels and greater share of market that will consider CHP
High R&D on Base Case	2,764	0	2,764	Rate of technology improvement accelerated 5 years
High Deployment Case	4,471	2,869	7,340	Accelerated technology improvement with aggressive market access and streamlining to improve customer attitudes and response

Source: EPRI, 2005

EPRI goes on to estimate that even the base case forecast of about 2 GW of installed CHP capacity would produce energy savings of 400 trillion BTUs over 15 years, close to $1 billion in reduced facility operating costs, and a CO_2 emissions reduction of 23 million tons. The high deployment case of 7.3 GW would increase the energy savings increase to 1,900 trillion BTUs, increase customer energy cost savings to $6 billion, increase CO_2 emissions reductions to 112 million tons (EPRI, 2005).

More recently, the Energy Commission has produced a "Distributed Generation and Cogeneration Policy Roadmap for California" (Energy Commission, 2007d). This report presents a vision for DG and CHP market penetration through 2020. The roadmap includes a set of policy recommendations to achieve a goal of market penetration of 3,300 MW of distributed CHP (individual installations less than 20 MW), as part of a total of 7,400 MW of overall DG, by 2020. This would be coupled with 11,200 MW of large CHP (individual installations greater than 20 MW), for a total of 14,500 MW of small and large CHP in California (compared with about 9,000 MW at present) by the 2020 timeframe (Energy Commission, 2007d).

In order to achieve this vision, the roadmap report calls for a near-term continuation of DG incentives, a medium-term transition to new market mechanisms, and concurrent efforts to reduce remaining institutional barriers. In order to transition from incentives to a market-driven expansion of DG/CHP, the report recommends: 1) promoting renewable DG/CHP through portfolio standards; 2) establishing market mechanisms to allow DG/CHP to compete with conventional central plant generation with T&D; and 3) creating access to emissions markets to help in appropriately valuing DG/CHP. The report includes consideration of incorporating these suggestions into future Energy Commission IEPR efforts, as well as further defining and refining specific recommendations with the aid of stakeholder input (Energy Commission, 2007d).

8. Summary of CHP System Financial Assistance Programs

In addition to the SGIP program that is discussed in a previous section, that provides a direct capital cost buy-down for qualifying CHP systems, there are additional financial assistance programs available for CHP system installation in California. These include federal tax programs, low interest loan programs for small businesses, and CHP project screening services that are available on a limited basis from the PRAC and the U.S. Environmental Protection Agency.

Federal investment tax credits for CHP system installation have been included under various energy policy legislation proposals in recent years. At present, investment tax credits are available for fuel cell and microturbine installations, but not for CHP systems more generally. A broader CHP federal investment tax credit of 10% was proposed under the 2005 Energy Policy Act, but was cut in the final conference meeting at least partly due to a shift in Office of Management and Budget methodology that showed the program to be a net resource consumer instead of a revenue generator. The USCHPA is currently working on a new proposal for a federal CHP investment tax credit, with either a 20 MW or 50 MW cap on qualifying system size.

Low-interest loans are available for small businesses in California that invest in energy efficiency improvement projects, including CHP projects. In cooperation with the Energy Commission, the State Assistance Fund for Enterprise, Business, and Industrial Development Corporation (SAFE-BIDCO) provides low-interest loans under its Energy Efficiency Loans program. The program is funded by federal oil overcharge funds. Small businesses are defined as those with a net worth below $6 million and net income below $2 million per year. Loan funds can be used for project design and consultant fees, and material and equipment costs. CHP projects are explicitly included as eligible projects, along with other energy efficiency, HVAC system, and energy management improvement projects (SAFE-BIDCO, 2007).

For energy end-users in California that are interested in potential CHP projects, both the PRAC and the U.S. EPA offer services to perform initial project screenings to determine CHP system feasibility, optimal system type and size, and potential system economics. The PRAC "Level 2" feasibility studies are conducted by San Diego State University, with a team of experts deployed to the site to collect equipment and energy use data and a year of utility bills. The CogenPro software package is then used to determine optimal system sizing and approximate system economics. Project screenings are offered by the PRAC on either a no-charge or cost-shared basis, depending on the nature of the potential installation.[11]

The U.S. EPA also offers initial CHP project screening services. Interested parties can contact EPA staff, and if qualified, can then fill out a data submittal form that is available on the U.S.

[11] For more details on PRAC CHP project feasibility screenings, please visit http://www.chpcenterpr.org or contact Dr. Asfaw Beyene directly at abeyene@rohan.sdsu.edu.

EPA CHP Partnership website. They will then receive a report with the findings from the "Level 1" screening analysis.[12]

9. Action Plan for Advancing the CHP Market in California

California is among the most advanced states in the U.S. with regard to development of DG and CHP resources. California's programs for renewable energy, DG interconnection through the Rule 21 process, and capital cost buy-down incentives for customer-owned generation are among the most progressive and well-developed of those anywhere in the U.S. However, despite these factors, several key issues and impediments remain for greater adoption of CHP to meet California's growing energy needs.

These issues and impediments include:

- difficulty by CHP system owners of systems typically larger than 20 MW in renewing utility contracts for projects that have been previously installed over the past twenty years as "Qualifying Facilities" as the contracts expire, threatening the continued use of up to 2 GW of existing CHP capacity in California;
- continued difficulties with integrating DG/CHP systems into existing utility transmission and distribution systems in many cases, as a result of "detailed interconnection study" requirements where utility grids are not ideally suited to accepting DG resources;
- inability of most CHP systems to export electricity to the grid as they do not qualify for "net metering" in California except where completely renewably powered (unlike in some states such as Connecticut);
- inability of CHP systems to provide power to nearby facilities across public roadways per Public Utilities Code Section 218; and
- disparate and hard to understand utility tariff structures for CHP system owners that are in some cases unfavorable to CHP system installation.

<u>Recommended Policy Actions</u>

In the near term, we recommend several policy actions to help to continue the important role of CHP in meeting California's energy needs in an environmentally responsible manner. These recommendations are as follows.

<u>1. Issue CPUC policy directives to utilities to require existing utility contracts for large CHP "qualifying facility" projects to be extended</u>

California currently has hundreds of MW of large (typically greater than 20 MW) CHP projects that are in jeopardy because of utility contracts that are set to expire, and that may or may not be extended. The CPUC could, and in our opinion should, issue a policy directive to require utilities to extend these contracts for "Qualifying Facilities" so that existing CHP assets in the state can continue to be utilized. In some cases, CHP QF projects are disadvantaged because they are not considered fully dispatchable, due to the need to match electrical output with local thermal energy requirements. While it is true that such CHP facilities may not be fully dispatchable in this sense, they are firm power generation resources that should be treated similarly as other QF resources.

[12] For more details, please visit: http://www.epa.gov/chp/project_resources/tech_assist.htm

We recommend that the CPUC issue policy directives to utilities to require existing utility contracts that are expiring for large "qualifying facility" CHP projects to be immediately extended (for a period of time to be determined by the CPUC) with parallel review of future energy demand needs and the roll of these large QF-CHP facilities in meeting these needs. We further recommend that the CPUC consider allowing net metering for these facilities regardless of system size, or at a minimum, allow them to back feed to the grid even at avoided costs rates without penalty. This will permit grid load support and permit sites to enjoy full thermal benefits without fear of penalty for back feed.

2. Enact *AB 2778* "clean up" legislation that provides for continued SGIP capital cost support for fossil fuel-based CHP that complies with current BACT or CARB certification requirements

When Gov. Schwarzenegger signed *AB 2778* into law, he indicated in a signing statement that he expected additional legislation to be enacted to extend the SGIP incentives for combustion-based as well as fuel cell and wind-powered DG (see Appendix C). In fact, the CPUC could extend this incentive without legislative action, but legislation would probably be the best way to extend the other aspects of the SGIP program in step with *AB 2778*. We recommend that incentives for combustion-based CHP technologies be extended at least through 2009, as their relative costs and benefits are being studied per *AB 2778*. We also recommend that combinations of capital cost and performance-based financial support schemes be examined in DG incentive programs for post-2009, as they may be more economically efficient than the simple ($/W) cost buy-down type of program.

3. Institute co-metering for CHP systems to allow for power export to the grid with rules for power purchase from CHP system owners based on wholesale power prices plus consideration for their T&D, grid support, and GHG reduction benefits

In some cases, CHP system sizes are limited by rules that restrict their ability to export power to utility grids, rather than by the thermal loads at the site. Allowing export of power from CHP systems to utility grids under a wholesale power market would entail administrative complexities for utilities and the CAISO, but we believe that in many cases these would be offset by the benefits that could be obtained. Export of power from CHP systems to utility grids could be accomplished through co-metering, whereby one utility meter measures power usage and a second meter measures power exports. Net exports of power could then be compensated at wholesale power rates, thus incentivizing CHP system operation at times of high electricity prices and peak system demand. These payments could potentially be augmented by consideration of T&D and grid support benefits, and environmental benefits in terms of reduced GHG emissions compared with those from conventional generation.

4. Encourage the use of CHP as a power reliability measure for critical need applications such as refineries, water pumping stations, emergency response data centers, etc.

CHP systems offer the potential for energy supply (both electrical and thermal) with reduced costs and environmental impacts compared with conventional systems. In settings that also require high-reliability power and that are currently backup up with rarely-used generator systems, CHP systems can provide the additional functionality of providing backup power with the incorporation of fuel storage to protect against fuel supply disruptions. The economics of CHP in these settings can be further enhanced through this combined functionality, whereby existing backup generators can be decommissioned and replaced with CHP systems that can provide day-to-day power along with emergency "black start" power services. The PRAC will be studying these applications in greater detail in 2007, in the context of specific premium power settings in the Pacific region.

5. Per the Energy Commission IEPR, provide a unique position in the utility loading order for CHP projects

A recent white paper developed by the Energy Commission assesses the potential for increased energy efficiency, demand response measures, and renewable and DG/CHP systems to become more heavily utilized as preferred options in the "loading order" for California's electricity resources. While DG/CHP systems are included in the report as a separate category of loading order resources, one could argue that these types of systems can also be considered even more highly-valued energy efficiency and/or demand response measures, depending on how they are implemented.

The Energy Commission white paper examines the potential benefits of expanded use of these types of resources, as well as institutional, technical, and regulatory barriers to their use. For DG/CHP systems, the paper identifies as barriers: 1) the need for additional utility resources to accommodate expanded use of DG/CHP; 2) lack of utility incentives to promote the use of these systems; and 3) lack of a comprehensive system for tracking and monitoring the output of DG/CHP systems (Energy Commission, 2005a).

With regard to this utility loading order issue, we support the passage of *AB 1613* that, as discussed above, would make it state policy that the conversion of waste heat to electricity or other useful purposes be treated as energy efficiency in the loading order. This would help to enable the goal of *AB 1613* to achieve 5,000 MW of new electrical generation by 2015 from CHP, as well as contributing to other state goals for GHG emission reductions.

6. Explore options for expanded use of renewable biogas in conjunction with onsite power generation through CHP, including the possibility of "wheeling" biogas through utility gas pipelines for use in CHP in other locations

High natural gas prices, coupled with uncertainty about future gas price volatility, represent a significant barrier to CHP adoption in California. Expanded use of biogas to power CHP projects is one option for removing gas price volatility from the economic equation, while using a renewable fuel in the process. PG&E recently became the first gas utility in the nation to develop a specification for injecting biogas into their natural gas pipeline network, so that the biogas could be used for power generation to help meet the utility's RPS obligation. In addition to projects that would use biogas for onsite CHP, we recommend that efforts be made to explore similar schemes to allow biogas to be injected into gas distribution pipelines for use in CHP projects in other areas connected to the pipeline network where CHP projects may be more favorable due to a better match between electrical and thermal loads. CHP system developers should have the right to bid for the rights to the biogas in the pipeline network, particularly since they can likely use it in a more efficient way (in an overall thermal efficiency sense) than can central power generation facilities.

7. In accordance with AB 32 for GHG reductions in California, develop a GHG credit scheme for CHP systems that could be used in the context of GHG emissions reduction credit trading systems

The passage of California's landmark GHG reduction bill is now leading to efforts to more specifically identify programs and strategies to reduce GHG emissions in the coming years. The ARB is now soliciting ideas for specific policy measures and programs that can lead to near and longer-term GHG emission reductions. CHP systems offer the potential to reduce GHG emissions compared with conventional generation because of enhanced energy efficiency and the potential to use waste-stream fuel sources that otherwise would produce higher levels of GHG emissions to the atmosphere (e.g. landfill gases, digester gases, restaurant cooking grease, etc.).

In this context, we propose an effort to develop a GHG credit scheme for CHP systems that consider the following factors, so that their benefits can be quantified and specifically included in future GHG "cap and trade" programs:

- CHP system "real world" efficiency including thermal credits for the specific setting involved;
- fuel type and associated "upstream" GHG emissions;
- impact (if any) on grid system operational efficiency;
- comparison with conventional or baseline electricity supply system emissions.

Consideration of these factors would allow for assessment of GHG emissions reductions from individual systems that could then be translated into tradable emission reduction credits. Alternately, a more generic system of credits could be developed, based on an average values of GHG emission reductions that could be expected for certain CHP system types. This would be less accurate for any particular installation, but easier to implement.

<u>8. Consider efforts to harmonize local air district emissions permitting and certification procedures within California</u>
At present, various air districts within California, or which there are 35, have different rules and in some cases emission limits for CHP and DG systems. The state should consider efforts to harmonize these rules and regulations so that manufacturers do not face a complicated "mosaic" of different air quality regulations throughout the state and have a fewer set of standards to meet.

<u>9. Also per the Energy Commission IEPR, the CPUC should direct utilities to make capacity payments for the transmission and distribution benefits of CHP systems</u>
As recommended by the Energy Commission IEPR, the CPUC should direct utilities to make capacity payments for the transmission and distribution benefits of CHP systems. As explained further in the 2007 IEPR, this could be combined with a scheme for CHP systems to be cost and revenue neutral from the utility perspective, but with the T&D benefit benefits accruing to the system owner to make CHP installation a beneficial economic investment. Along with this, the CPUC and the Energy Commission should coordinate efforts with the utilities to develop and implement planning models to determine where in utility grids DG/CHP systems, whether in the singular or aggregate, would be most beneficial in terms of the transmission and distribution benefits. These benefits include, but are not limited to congestion relief and deferral or elimination of T&D upgrades.

<u>10. Consider CPUC direction to the major California utilities to develop more consistent and favorable utility tariff structure for CHP customers</u>
The prospects for CHP system installation in California are complicated and made difficult by regionally differing and periodically changing utility rate structures. Making these tariff structures more consistent and less disadvantageous for customers that choose to install CHP systems would help to reduce complexity and otherwise improve the prospects for CHP system penetration to contribute to state energy and environmental goals.

Specifically, CHP system owners are disadvantaged when short periods of system downtime in a given month negate their savings of facility-related demand charges. It is in general reasonable for utility operators to insist that CHP facilities be reliable and available, but a system downtime of e.g. 15 minutes per month is enough to eliminate demand charge savings in many cases, and this translates into an availability of over 99.9%. Meanwhile, independent power producers subject to power purchase agreements are typically expected to achieve system availabilities of 90-95%. We recommend that the PUC establish regulations such that demand charges are assessed over 1 or 2-hour blocks, rather than 15 or 30 minutes, so that brief periods of system downtime do not negatively impact CHP system economics in an unreasonable fashion.

10. Conclusions

In conclusion, California has historically been one of the most attractive states in the U.S. for CHP because of the combination of high electricity prices and favorable DG/CHP interconnection and incentive policies. California's stringent new DG air quality regulations, coupled with the recent lapse in SGIP incentive funds for most CHP technologies, pose a challenge for CHP system installation at the present time. However, several small fuel cell and microturbine systems have already certified to the 2007 ARB emission limits. Furthermore, some sites, particular with large thermal and/or "premium power" needs, may still find attractive economics to installing CHP in California. Larger CHP systems that are individually permitted require BACT systems for emission control, which creates a heavy financial burden for medium-sized systems in the 1-5 MW range.

In this context, California is currently at a crossroads with regard to the future CHP market. If the existing legacy systems that are nearing the end of their design lives can be re-powered and/or re-permitted, and supportive incentive and other policies can be maintained, we believe that the California CHP market can continue to expand even with the new more stringent air pollutant emission limits. However, if supportive policies are not further developed, to both encourage energy efficiency and to help meet the goals of California's *AB 32* greenhouse gas law, CHP market development in the state is likely to be seriously challenged.

With regard to these remaining issues and obstacles to further market penetration for CHP in California, the recently released Energy Commission "Distributed Generation and Cogeneration Policy Roadmap for California" addresses several of these issues in what appears to be a reasonable and sound manner (CEC, 2007d). Along with the recommendations we make here, we support the major recommendations of the roadmap report in the context of important state goals for energy efficiency and GHG emissions reductions. We believe that these goals can be achieved along with economic benefits for utility customers who choose to install CHP, providing a "win-win" scenario for the state.

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Appendix A – Distributed Power Generation Interconnections Under California Rule 21

Table A-1: Summary of DG System Interconnections under California Rule 21 (2001 through mid-2006)

	Number of Projects	MW of Capacity
Authorized to Interconnect in 2001:	31	77.5
Southern California Edison	12	33.7
Pacific Gas & Electric	3	6.9
San Diego Gas & Electric	16	36.9
Authorized to Interconnect in 2002:	89	215.8
Southern California Edison	43	119.7
Pacific Gas & Electric	27	67.7
San Diego Gas & Electric	19	28.3
Authorized to Interconnect in 2003:	133	83.1
Southern California Edison	60	51.6
Pacific Gas & Electric	59	27.6
San Diego Gas & Electric	14	3.9
Authorized to Interconnect in 2004:	110	104.2
Southern California Edison	32	26.4
Pacific Gas & Electric	68	62.3
San Diego Gas & Electric	10	15.5
Authorized to Interconnect in 2005:	16	7.2
Southern California Edison	11	2.5
Pacific Gas & Electric	0*	0.0
San Diego Gas & Electric	5	4.6
Authorized to Interconnect in 2006:	154	119.0
Southern California Edison	not reported	N/A
Pacific Gas & Electric	150	117.3
San Diego Gas & Electric	4	1.7
Pending Interconnections (as of mid-2006):	159	191.5
Southern California Edison	70	123.0
Pacific Gas & Electric	82	55.3
San Diego Gas & Electric	7	13.2
Total Interconn. Completed (2001 - mid-2006):	**533**	**606.8**
Southern California Edison	**158**	**234.0**
Pacific Gas & Electric	**307**	**281.8**
San Diego Gas & Electric	**68**	**91.0**

Source: Energy Commission (2007b)

Appendix B – Example Utility Rate Schedule for DG/CHP Customer

SCHEDULE E—DCG DEPARTING CUSTOMER GENERATION, CG

APPLICABILITY: This schedule is applicable to customers that have Customer Generation Departing Load as defined below, including customers who displace all or a portion of their load with Customer Generation and including new load served by Customer Generation as set forth in Special Condition 6 below.

TERRITORY: The entire territory served.

RATES: Customers under this schedule are responsible for the following charges unless expressly excepted or exempted from such charges under Special Condition 2 below:

1. DWR BOND CHARGE: The Department of Water Resources (DWR) Bond Charge recovers DWR's bond financing costs, and is set by dividing the annual revenue requirement for DWR's bond-related costs by an estimate of the annual consumption not excluded from this charge. The DWR Bond Charge is the property of DWR for all purposes under California law. The DWR Bond Charge applies to Customer Generation Departing Load unless sales under the customer's Otherwise Applicable Rate Schedule were CARE or medical baseline or unless exempted or excepted under Special Condition 2 below. The DWR Bond Charge is separately shown in the customer's Otherwise Applicable Rate Schedule. PG&E shall begin billing applicable Customer Generation Departing Load for the DWR Bond Charge, as of September 1, 2004. Unrecovered DWR Bond Charges from April 3, 2003, the effective date of Commission Decision (D.) 03-04-030 through August 31, 2004, shall be recovered from applicable Customer Generation Departing Load as provided for in Commission Resolution E-3909.

2. POWER CHARGE INDIFFERENCE ADJUSTMENT: The adjustment (either a charge or credit) intended to ensure that customers that purchase electricity from non-utility suppliers pay their share of cost for generation acquired prior to 2003. The Power Charge Indifference Adjustment applies to Customer Generation Departing Load unless exempted or excepted under Special Condition 2 below. The Power Charge Indifference Adjustment is equal to -$0.00009 per kilowatt-hour. (I)

3. COMPETITION TRANSITION CHARGE (CTC): The Ongoing CTC recovers the cost of power purchase agreements, signed prior to December 20, 1995, in excess of a California Public Utilities Commission (Commission) approved proxy of the market price of electricity plus employee transition costs as defined in Section 367(a) of the California Public Utilities Code. The Ongoing CTC applies to the Customer Generation Departing Load unless exempt under Special Condition 2 below. The currently approved CTC rate is equal to $0.00013 per kilowatt-hour. (R)

(Continued)

SCHEDULE E—DCG DEPARTING CUSTOMER GENERATION, CG
(Continued)

RATES: (Cont'd.)

4. NUCLEAR DECOMMISSIONING (ND) CHARGE: The ND charge collects the funds required to restore the site when PG&E's nuclear power plants are removed from service. The ND charge applies to all Customer Generation Departing Load unless exempt under Special Condition 2 below. The ND charge is separately shown in the customer's otherwise Applicable Rate Schedule. (N)

5. REGULATORY ASSET (RA) CHARGE: The RA charge recovers the costs associated with the Regulatory Asset adopted by the Commission in D.03-12-035. The Regulatory Asset is separately shown in the customer's Otherwise Applicable Rate Schedule. On March 1, 2005, the Energy Cost Recovery Amount (ECRA) superceded and replaced the RA Charge such that after March 1, 2005, applicable customers no longer incur additional RA Charges but instead incur Energy Cost Recovery Amount (ECRA) charges. (L) (N)

6. PUBLIC PURPOSE PROGRAM (PPP) CHARGE: The PPP charge collects the costs of state mandated low income, energy efficiency and renewable generation programs. The PPP charge applies to all Customer Generation Departing Load unless exempt under Special Condition 2 below. The PPP charge is separately shown in the customer's Otherwise Applicable Rate Schedule.

7. TRUST TRANSFER AMOUNT (TTA) CHARGE: The TTA funds the cost of bonds used to pay for a 10 percent rate reduction for residential and small commercial customers. The TTA has been transferred to a subsidiary of PG&E and then to a public trust. PG&E is collecting the TTA on behalf of the subsidiary and public trust. The TTA does not belong to PG&E. The TTA charge applies to all Customer Generation Departing Load that would have otherwise been responsible for the TTA as specified in Schedule RRB, unless exempt under Special Condition 2 below. The TTA charge is separately shown in the customer's Otherwise Applicable Rate Schedule.

8. ENERGY COST RECOVERY AMOUNT (ECRA): The ECRA charge recovers the costs associated with the Energy Recovery Amount adopted by the Commission in Decision 04-11-015. The Energy Cost Recovery Amount is shown in the customer's Otherwise Applicable Rate Schedule. On March 1, 2005, the ECRA superceded and replaced the RA Charge. (N)

(Continued)

SCHEDULE E—DCG DEPARTING CUSTOMER GENERATION, CG
(Continued)

SPECIAL CONDITIONS:

1. DEFINITIONS: The following terms when used in this tariff have the meanings set forth below:

   a. Customer Generation: Customer Generation means cogeneration, renewable technologies, or any other type of generation that: (1) is dedicated wholly or in part to serve all or a portion of a specific customer's load; and (2) relies on non-PG&E or dedicated PG&E distribution wires rather than PG&E's utility grid to serve the customer, the customer's affiliates and/or tenants, and/or not more than two other persons or corporations, provided that those two persons or corporations are located on site or adjacent to the real property on which the generator is located. For the purpose of applying this tariff, county and municipal water district self-generation which is used to serve the district's own loads, whether on-site or off-site, is also considered to be Customer Generation, pursuant to Commission Decision by Decision 05-06-041. County and municipal water district generation serving off-site loads other than the district's own loads is not considered to be Customer Generation under this tariff, unless the service is provided over-the-fence in accordance with Public Utility Code Section 218. (N)

   b. Customer Generation Departing Load: Customer Generation Departing Load is that portion of a PG&E electric customer's load for which the customer, on or after December 20, 1995: (1) discontinues or reduces its purchases of bundled or direct access electricity service from PG&E; (2) purchases or consumes electricity supplied and delivered by Customer Generation to replace the PG&E or direct access purchases; and (3) remains physically located at the same location or elsewhere within PG&E's service area as it existed on April 3, 2003. Reductions in load are classified as Customer Generation Departing Load only to the extent that such load is subsequently served with electricity from a source other than PG&E. New customer load not specifically excluded below shall be deemed Customer Generation Departing Load for purposes of this schedule.

      Customer Generation Departing Load specifically excludes:

      (1) Changes in usage occurring in the normal course of business resulting from changes in business cycles, termination of operations, departure from the utility service territory, weather, reduced production, modifications to production equipment or operations, changes in production or manufacturing processes, fuel switching, enhancement or increased efficiency of equipment or performance of existing Customer Generation equipment, replacement of existing Customer Generation equipment with new power generation equipment of similar size, installation of demand-side management equipment or facilities, energy conservation efforts, or other similar factors.

      (2) New customer load or incremental load of an existing customer where the load is being met through a direct transaction with Customer Generation and the transaction does not otherwise require the use of transmission or distribution facilities owned by PG&E.

      (3) Load temporarily taking service from a back-up generation unit during emergency conditions called by PG&E, the California Independent System Operator, or any successor system operator. This exclusion also applies to dispatchable backup generation used in connection with the dispatch of a load management program sponsored by the Commission, California Energy Commission or California Independent System Operator, or any successor system operator.

(Continued)

SCHEDULE E—DCG DEPARTING CUSTOMER GENERATION, CG
(Continued)

SPECIAL CONDITIONS: (Cont'd.)

1. DEFINITIONS: (Cont'd.)

   b. Customer Generation Departing Load: (Cont'd.)

      (4) Load that physically disconnects from the utility grid.

      (5) Changes in the distribution of load among accounts at a customer site with multiple accounts, load resulting from the reconfiguration of distribution facilities on the customer site, provided that the changes do not result in a discontinuance or reduction of service from PG&E at that location.

   c. Otherwise Applicable Rate Schedule: The Otherwise Applicable Rate Schedule shall be the last schedule under which the customer took service before load was displaced by Customer Generation. Where the departing load was not previously served by a utility, the Otherwise Applicable Schedule will be the rate schedule the customer would have taken service under, had the load been served by PG&E.

2. EXEMPTIONS AND EXCEPTIONS: Customer Generation Departing Load is exempted or excepted from some or all of the rates described above to the extent set forth below. Unless exempted or excepted in Special Conditions 2.a. through 2.h., all usage displaced from the grid by the Customer Generation is subject to the DWR Bond Charge, Power Charge Indifference Adjustment, CTC, ND Charge, (T) PPP Charge, TTA Charge, and either RA Charge or ECRA Charge. In the case of net metered customers, these charges will be calculated based on net consumption, except as provided in future Commission decisions.

   a. Load That Departed As Of February 1, 2001. Customer Generation Departing Load that began to receive service from Customer Generation on or before February 1, 2001, except during any period and to the extent that the Customer Generation Departing Load thereafter receives bundled or direct access service, is exempt from the DWR Bond Charge, Power Charge (T) Indifference Adjustment, RA Charge, and ECRA Charge.

   b. Grandfathered Load. Customer Generation Departing Load, not otherwise exempted under Special Condition 2.a. above, or Special Condition 2.c., 2.d., 2.e., or 2.h. below, that commenced commercial operation on or before January 1, 2003, or for which (a) an application for authority to construct was submitted to the lead agency under the California Environmental Quality Act, not later than August 29, 2001, and (b) commercial operation commenced not later than January 1, 2004, is exempted from the Power Charge Indifference (T) Adjustment, RA Charges, and ECRA Charge.

   c. Biogas Digesters. Customer Generation Departing Load served by an eligible biogas digester customer-generator, as defined in Public Utilities Code Section 2827.9, is exempt from the DWR Bond Charge, Power Charge (T) Indifference Adjustment, RA Charge, ECRA Charge, ND Charge, PPP Charge, TTA Charge and CTC, to the extent that such load falls within the Customer Generation Cap described in Special Condition 2.g. below.

(Continued)

SCHEDULE E—DCG DEPARTING CUSTOMER GENERATION, CG
(Continued)

SPECIAL CONDITIONS: (Cont'd.)

2. EXEMPTIONS AND EXCEPTIONS: (Cont'd.)

d. Clean Customer Generation Systems Under 1 MW. Customer Generation Departing Load under 1 megawatt (MW) in size that is eligible for (i) net metering, or (ii) financial incentives from the Commission's self-generation program, or (iii) financial incentives from the California Energy Commission, is excepted from the DWR Bond Charge, Power Charge Indifference Adjustment, RA Charge, ECRA Charge, and the CTC, to the extent that such load falls within the Customer Generation Cap described in Special Condition 2.g. below. (T)

e. Ultra-Clean and Low-Emission Customer Generation Systems over 1 MW. Customer Generation Departing Load that is over 1 MW in size but that otherwise meets all criteria in Public Utilities Code Section 353.2 as "ultra-clean and low-emissions" is exempt from the Power Charge Indifference Adjustment, RA Charge, and ECRA Charge to the extent that such load falls within the Customer Generation Cap as described in Special Condition 2.g. below. (T)

f. Other Customer Generation Systems. Customer Generation Departing Load that employs best available control technology standards set by local air quality management districts and/or the California Air Resources Board, as applicable, and is not (a) back-up generation, (b) diesel-fired generation, or (c) discussed in Special Conditions 2.a. through 2.e. above, is exempted from the Power Charge Indifference Adjustment, RA Charge, and ECRA Charge to the extent that such load falls within the Customer Generation Cap described in Special Condition 2.g. below. (T)

g. Customer Generation Cap. The exemptions or exceptions described in Special Conditions 2.c., 2.d., 2.e., and 2.f. above shall expire when the cumulative total of Customer Generation Departing Load eligible under Special Conditions 2.c., 2.d., 2.e., and 2.f. (and the corresponding tariff sections for other electric utilities under the Commission's jurisdiction) exceeds 3,000 MW, as determined on a first-come, first-served basis by the California Energy Commission. In addition, the exemptions or exceptions described in Special Condition 2.f. above shall be limited to 1,500 MW (of the total 3,000 MW) with no more than 600 MW by the end of 2004, an additional 500 MW by July 1, 2008, and a final 400 MW thereafter.

The University of California and California State University (UC/CSU) are granted a set-aside within the overall Customer Generation Cap as follows: 10 MW by the end of 2004, an additional 80 MW by the end of 2008, and an additional 75 MW thereafter.

(Continued)

SCHEDULE E—DCG DEPARTING CUSTOMER GENERATION, CG
(Continued)

SPECIAL CONDITIONS: (Cont'd.)

3. EXEMPTIONS AND EXCEPTIONS: (Cont'd.)

h. CTC Exemptions for Cogeneration. The following Customer Generation Departing Load is exempt from CTCs:

(1) Load served by an on-site or over-the-fence non-mobile self-cogeneration or cogeneration facility, per Public Utilities Code Section 372(a)(4).

(2) Load served by existing, new, or portable emergency generation equipment that is used during periods when service from PG&E is unavailable, per Public Utilities Code Section 372(a)(3), provided such equipment is not operated in parallel with PG&E's power grid other than on a momentary basis.

i. Clarification Regarding Continuous Direct Access Customers. If, a customer took direct access service before February 1, 2001, and continued on direct access service through September 20, 2001, and is therefore exempt from the DWR Bond Charge, Power Charge Indifference Adjustment, RA Charge, (T) and ECRA Charge for its electric load, then that customer shall continue to be exempt regardless of whether or not such customer installs Customer Generation.

3. PROCEDURES FOR CUSTOMER GENERATION DEPARTING LOAD: Customers are obligated to notify PG&E of their intent to become Customer Generation Departing Load in accordance with the following procedure:

a. Customer Notice to PG&E: Customers shall notify PG&E, in writing or by reasonable means through a designated PG&E representative authorized to receive such notification, of their intention to take steps that will qualify their load or some portion thereof as Customer Generation Departing Load at least 30 days in advance of discontinuation or reduction of electric service from PG&E. The customer shall specify in its notice the following:

(1) The date of the departure or reduction of load (Date of Departure);

(2) A description of the load that will depart or be reduced;

(3) The PG&E account number assigned to this load;

(4) The type of Customer Generation technology; and

(5) An identification of any exemptions that the customer believes are applicable to the load.

Failure to provide notice will constitute a violation of this tariff and breach of the customer's obligations to PG&E.

(Continued)

Appendix C – Gov. Schwarzenegger's AB 2778 Signing Statement

To the Members of the California State Assembly:

I am signing Assembly Bill 2778.

This bill extends the sunset on the Self Generation Incentive Program to promote distributed generation throughout California. However, the legislation eliminated clean combustion technologies like microturbines from the program.

I look forward to working with the legislature to enact legislation that returns the most efficient and cost effective technologies to the program. If clean up legislation is not possible, the California Public Utilities Commission should develop a complimentary program for these technologies.

Sincerely,

Arnold Schwarzenegger

Appendix D – Contact Information for Key Pacific Region CHP Organizations

Note: To be added to this database, or to make any corrections, please send an email to Tim Lipman at telipman@berkeley.edu

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2008 Combined Heat and Power Baseline Assessment and Action Plan for the Hawaii Market

Final Project Report

September 30, 2008

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Legal Notice

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Kevin Best Real Energy	Charlie Senning The Gas Company
Keith Davidson DE Solutions, Inc.	Irene Stillings California Center for Sustainable Energy (formerly the San Diego Regional Energy Office)
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Table of Contents

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Executive Summary

The purpose of this report is to provide an updated baseline assessment and action plan for combined heat and power (CHP) in Hawaii and to identify the hurdles that prevent the expanded use of CHP systems. This report has been prepared by the Pacific Region CHP Application Center (PRAC). The PRAC is a United States Department of Energy (DOE) and California Energy Commission sponsored center to provide education and outreach assistance for CHP in the Pacific region of California, Nevada, and Hawaii. The PRAC is operated by the University of California – Berkeley (UCB), the University of California – Irvine (UCI), and San Diego State University (SDSU).

The information presented in this report is intended to provide:

- an overview of the current installed base of CHP systems in Hawaii;
- a summary of the technical and economic status of key CHP system technologies;
- a summary of the utility interconnection and policy environment for CHP in Hawaii;
- an assessment of the remaining market potential for CHP systems in Hawaii;
- an "action plan" to further promote CHP as a strategy for improving energy efficiency and reducing emissions from Hawaii's energy system; and
- an appendix of contacts for key organizations involved in the Hawaii CHP market.

The Hawaii CHP Landscape

Hawaii currently has approximately 500 MW of installed CHP capacity, or 24% of total electricity generating capacity in the state. The Pacific region of California, Hawaii and Nevada has over 9 GW of CHP capacity, most of which is in California. The average capacity of Pacific region CHP installations is 10.7 MW, and 55% of the CHP capacity is in large industrial systems of 50 MW or greater (Hedman, 2006). CHP systems in the western states of California, Hawaii, Nevada, and Arizona are estimated to be saving more than 370 trillion BTUs of fuel and 50 billion tons of CO_2 emissions per year, compared with the conventional generation they have replaced (Hedman, 2006).

Hawaii's electrical services are provided by one investor-owned utility company (known as an "IOU") and one island cooperative. There is currently one provider of electric services on each island that supplies power to the vast majority of homes and businesses. Hawaii Electric Light Company (HELCO) is the provider of electric utility services on the island of Hawaii. Maui Electric Company (MECO) is the provider of electric utility services on the islands of Maui, Lanai, and Molokai. Hawaiian Electric Company (HECO) is the provider of electric utility services on Oahu and is the parent company of MECO and HELCO. Kauai Island Utility Cooperative (KIUC) is the provider of electric utility service on the island of Kauai. The Gas Company provides utility gas services throughout the state of Hawaii.

Technical and Economic Status of Key CHP Technologies

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. See Table ES-1 below for a summary of key characteristics of each of the commercially available types of generators. Fuel cell systems are in an early commercial phase at present, with relatively high capital costs and an uncertain "track record" for O&M costs.

Table ES-1: CHP System Characteristics
(From the Combined Heat & Power Resource Guide and adjusted for Hawaii where noted)

Reciprocating IC Engines	**Capacity Range (kW)**	**100 – 500**	**500 – 2,000**
	Electric Generation Efficiency, % of LHV of Fuel	24 – 28	28 – 38+
	Installed Cost, $/kW (with Heat Recovery)	Up to 3,500[a]	Up to 3,000[a]
	O & M Costs, $/kWh	0.025[a]	0.025[a]
Gas Turbines	**Capacity Range (kW)**	**1,000 – 10,000**	**10,000 – 50,000**
	Electric Generation Efficiency, % of LHV of Fuel	24 – 28	31 – 36
	Installed Cost, $/kW (with Heat Recovery)	1,500	1,000
	O & M Costs, $/kWh	0.015	0.012
Micro-turbines	**Capacity Range (kW)**	**100 – 400**	
	Electric Generation Efficiency, % of LHV of Fuel	25 -30	
	Installed Cost, $/kW (with Heat Recovery)	2,000	
	O & M Costs, $/kWh	0.015	

Notes:
[a] Estimate adjusted for Hawaii installations.

Summary and Status of CHP Policy Issues in Hawaii

The policy context for CHP in Hawaii is complex and multi-faceted. Hawaii has simplified interconnection rules for small renewables and other interconnection guidelines that cover all other distributed generation (DG). The state has simplified interconnection rules and allows for net metering of solar, wind, biomass, and hydroelectric unites up to 50 kW. An external disconnect is required. Mutual indemnification requirements exist, but otherwise there are no additional insurance requirements. Rule 14 covers the interconnection of DG systems. An external disconnect is also required for these systems.

Hawaii's largest utility, HECO, has a set of simple interconnection guidelines. Hawaii's other primary utility -- KIUC -- currently has no interconnection standard. A proposed standard is under review by the PUC and interveners in an open docket 2006-0498. The Public Utility

Commission (PUC), created a docket (No. 03-0371) to review and improve the state's DG regulations in 2003. The PUC released its Decision and Order on 03-0371 on January 27, 2006.

Utility rates and standby fees are important and controversial aspects of CHP, and ones that are constantly changing – especially in Hawaii recently. Recent Hawaii PUC dockets have examined proposed standby charges by the utilities, and these dockets have allowed the PUC, the state's "consumer advocate," and all other parties to examine the assumptions and methodologies used to determine these costs and its impact to the deployment of beneficial and economic CHP generation in Hawaii. The latest decision has allowed utilities to propose higher standby charges as part of larger utility rate cases in the 2010 timeframe, rather than keeping them at their present level of $5/kW-month through 2014 as had been proposed (for the next 5 MW of CHP installed in the state). Further details of the current status of the utility/rate standby charge situation in Hawaii is explained in detail in Section 6 of this report.

On May 3, 2007, Hawaii passed *House Bill 226 (Thielen)* the "Global Warming Solutions Act of 2007." The bill requires the state to identify all sources of greenhouse gases, regulate greenhouse gases as a pollutant, and reduce emissions to 1990 levels by 2020 (and further thereafter). While the details of this legislation have yet to be worked out, the goal of reducing emissions of greenhouse gases may provide an incentive for advancing the CHP market in the state because of the greater energy efficiency and reduced emissions that CHP systems can provide relative to conventional grid power.

More recently, on January 31, 2008, Hawaii's Gov. Lingle signed a memorandum of understanding with U.S. DOE for the "Hawaii-DOE Clean Energy Initiative." The goal of this initiative is to decrease energy demand, accelerate the use of renewable and indigenous energy sources in Hawaii, and establish a target of 70% renewable energy in Hawaii by 2030 (DBEDT, 2008).

<u>The Market Potential of CHP Systems in Hawaii</u>
Hawaii is an exciting and economically attractive market opportunity for CHP. In general, the economic conditions for CHP in Hawaii are aided by high prevailing electricity prices, but hindered by relatively high gas prices. All of Hawaii's natural gas is synthetic natural gas (SNG)[1] derived from naphtha. The SNG is provided through The Gas Company's utility business, which is regulated in its rate offerings by the state PUC. The Gas Company also sells regulated and non-regulated propane to those customers without access to SNG. Propane prices in Hawaii are determined by The Gas Company's procurement costs, and are closely tied to the price of oil that is imported into the state. The Gas Company purchases its propane or "liquefied petroleum gas" (LPG) from two local refineries as well as offshore suppliers. This LPG, along with SNG, is used to meet the needs of their customers. There are no naturally occurring sources of petroleum products or natural gas in Hawaii.

In order to support the adoption of CHP, The Gas Company offers its non-utility and utility propane customers who install CHP dedicated propane gas rates. These rates are specifically designed to assist CHP customers by lowering operating costs and managing pricing risk

<u>Summary of CHP System Financial Assistance Programs</u>
There are limited financial assistance programs available for CHP system installation in Hawaii. These include federal tax programs and CHP project screening services that are available on a

[1] The Gas Company's SNG consists of 80% methane, 10% hydrogen, 5% butane, and 5% carbon dioxide.

limited basis from the PRAC and the U.S. Environmental Protection Agency. These programs are discussed in Section 8 of the main text of this report.

Action Plan for Advancing the CHP Market in Hawaii

The final section of this report presents a series of ideas for further advancing the CHP market in Hawaii. Key recommendations include:

1. Issue HPUC policy directives to reject the proposed tariffs in their entirety and require the utilities to resubmit tariffs that are fair, balanced, and non-discriminatory to both those who do and who do not choose to self-generate their electrical power.
2. Enact legislation that provides relief from regulatory hurdles that add difficulty and cost to developing and interconnecting projects.
3. Institute a more even playing field, that recognizes and incentives the environmental and grid benefits of DG/CHP.
4. Encourage standards, codes, permitting, and zoning rules that are not biased toward central power station generation.
5. Adapt the most successful of the CHP policies from other states to Hawaii's unique market.
6. Examine and consider implementing a research, development, and demonstration (RD&D) program for clean DG/CHP in Hawaii

See Section 9 of the main text of this report for further elaboration of these "action plan" concepts.

Conclusions

Hawaii represents an attractive market opportunity for CHP due to a combination of economic conditions, strong growth in demand for energy services, and energy and environmental concerns. There currently is approximately 500 MW of CHP capacity in the state, although some of this capacity is represented by relatively old projects of which some may no longer be operational.

CHP economics in Hawaii are both island and site specific. On Oahu, projects can be attractive where there is a good use for thermal energy that matches the profile of electrical output. On the other major islands of Hawaii, Maui, and Kauai, economics are more attractive due to the very high cost of electrical power. Efficiently designed projects can easily be attractive on these islands.

The greatest immediate threat to the CHP market in Hawaii is the large increase in standby charges for CHP projects that are being proposed by the major island utilities. If these charges are implemented, CHP economics will be dramatically affected and may no longer be attractive except possibly in the very best settings. We hope that moving forward, changes in electricity tariff structures are made carefully and fairly, and in ways that do not preclude the important principle of customer choice with regard to the provision of electrical services for commercial and industrial sites in the state.

1. Introduction

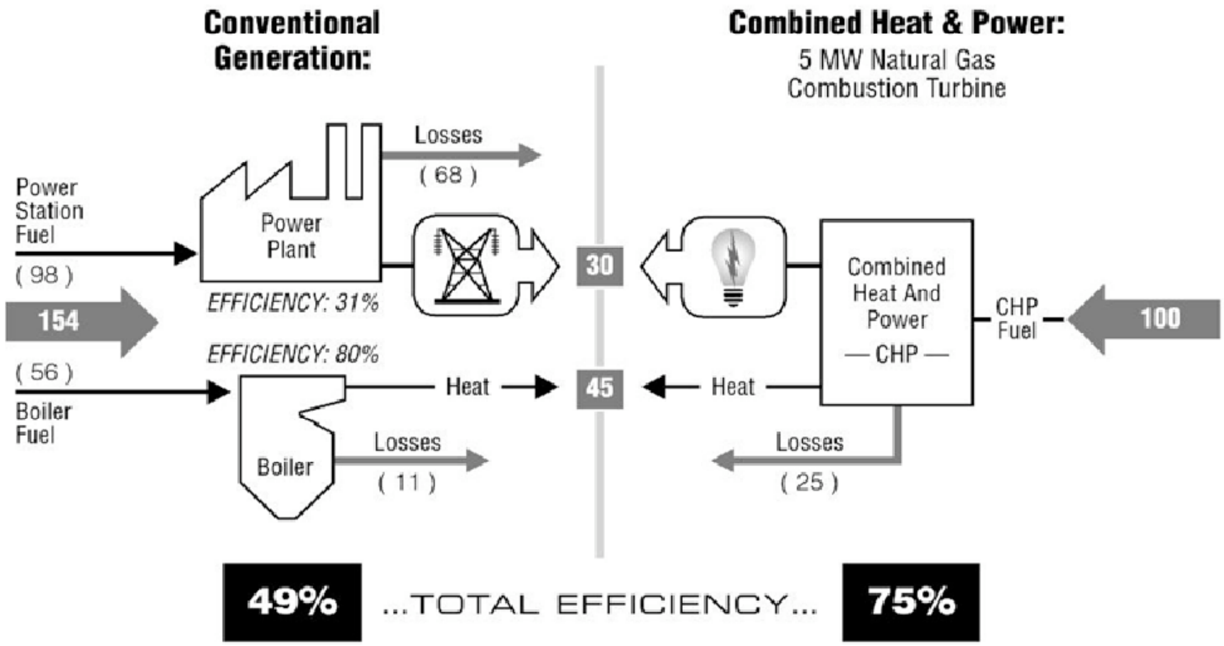
The purpose of this report is to assess the current status of combined heat and power (CHP) in Hawaii and to identify the hurdles that prevent the expanded use of CHP systems. This report has been prepared by the Pacific Region CHP Application Center (PRAC). The PRAC is a United States Department of Energy (DOE) and California Energy Commission sponsored center providing education and outreach assistance for CHP in the Pacific region of California, Nevada, and Hawaii. The PRAC is operated by the University of California – Berkeley (UCB), the University of California – Irvine (UCI), and San Diego State University (SDSU).

The information presented in this report is intended to provide:

- an overview of the current installed base of CHP systems in Hawaii;
- a summary of the economic status and conditions for CHP systems in Hawaii;
- a summary of the utility interconnection and policy environment for CHP in Hawaii;
- an assessment of the remaining market potential for CHP systems in Hawaii;
- an "action plan" to further promote CHP as a strategy for improving energy efficiency and reducing emissions from Hawaii's energy system; and
- an appendix of contacts for key organizations involved in the Pacific Region CHP market.

As a general introduction, CHP is the concept of producing electrical power onsite at industrial, commercial, and residential settings while at the same time capturing and using waste heat from electricity production for beneficial purposes. CHP is a form of distributed generation (DG) that offers the potential for highly efficient use of fuel (much more efficient than current central station power generation) and concomitant reduction of pollutants and greenhouse gases. CHP can also consist of producing electricity from waste heat or a waste fuel from industrial processes.

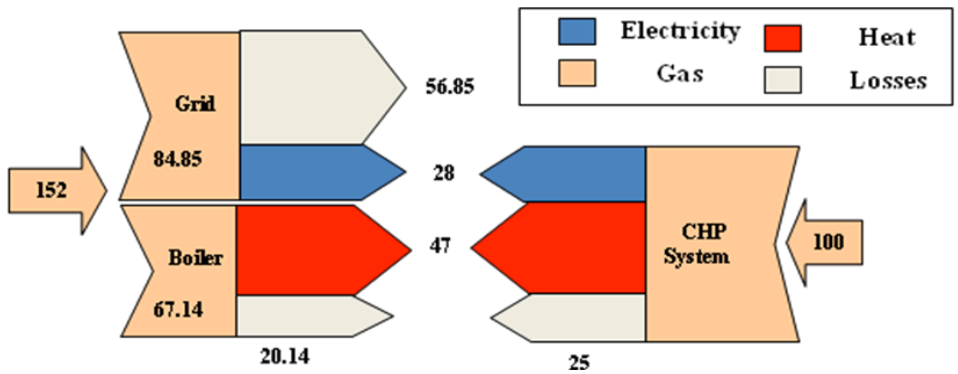
The following figures depict the manner in which CHP systems can provide the same energy services as separate electrical and thermal systems, with significantly less energy input. As shown in Figure 1, to provide 30 units of electricity and 45 units of heat using conventional generation would require energy input of 154 units. A typical CHP system using a 5 MW combustion turbine could provide these same energy services with only 100 units of energy input, thereby saving net energy, cost, and greenhouse gas emissions. Somewhat smaller systems in the 500 kW to 1 MW range, which would be more typical for the Hawaii market, could offer similar energy savings as their energy efficiency ratings would be similar to those of the 5 MW case shown below.



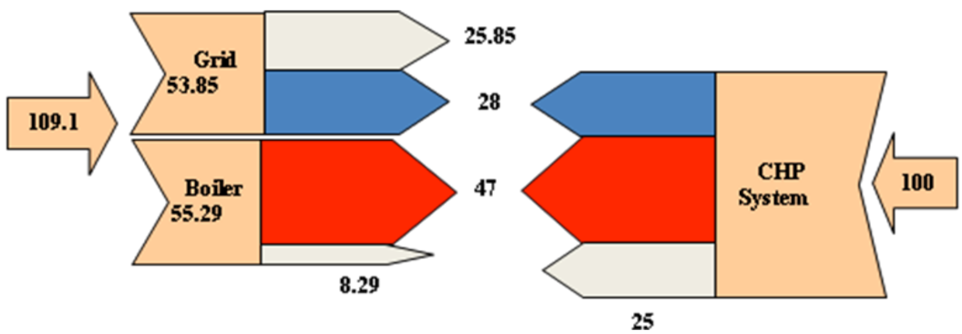
Source: Hedman, 2006

Figure 1: CHP Flow Diagram Based on 5 MW Combustion Turbine (generic energy units)

Figure 2 shows a more generalized depiction of the same concept. Compared with typical conventional generation, a present-day CHP system could provide the same electrical and thermal energy services with approximately two-thirds of the energy input. Even compared with a much advanced and more efficient combination of utility grid power and boiler technology in the future, the CHP system can still compete favorably. And of course the efficiencies of CHP "prime mover" technologies are also expected to improve over time.



Typical Conventional Generation



Advanced Technology for Grid and Boiler Technology

Figure 2: Generic CHP Flow Diagrams Compared with Typical and Advanced Conventional Generating Systems (generic energy units)

In addition to improving energy efficiency by capturing waste heat for thermal energy uses, CHP systems eliminate transmission and distribution (T&D) losses inherent in power produced from conventional centralized generation. These T&D losses are typically in the range of 7-11% of the amount of power delivered (Borbely and Kreider, 2001). CHP systems can also provide important grid “ancillary services” such as local voltage and frequency support and reactive power correction (i.e. “VARs”), and emergency backup power when coupled with additional electrical equipment to allow for power “islands” when the main utility grid fails.

Recognizing the potential of CHP to improve energy efficiency in the U.S., the DOE established a “CHP Challenge” goal of doubling CHP capacity from 46 GW in 1998 to 92 GW by 2010 (U.S. CHPA, 2001). As of 2006, there were an estimated 83 GW of CHP installed at 3,168 sites in the U.S., representing about 9% of total generating capacity in the country (Bautista et al., 2006). This suggests that the nation is generally on track to meet the DOE goal of 92 GW by 2010. However, new capacity additions appear to have slowed in recent years, with less than 2 GW installed in 2005 compared with about 4 GW in 2003 and 2004, and over 6 GW in 2001 (Bautista et al., 2006).

2. Report Purpose

As noted above, the purpose of this report is to assess the current status of combined heat and power (CHP) in Hawaii and to identify the hurdles that prevent the expanded use of CHP systems. The report summarizes the CHP "landscape" in Hawaii, including the current installed base of CHP systems, the potential future CHP market, and the status of key regulatory and policy issues. The report also suggests some key action areas to further expand the market penetration of CHP in Hawaii as an energy efficiency, cost containment, and environmental strategy for the state.

An additional purpose of the report is to alert stakeholders in Hawaii of the creation of the U.S. DOE "regional application centers" (or "RACs") for CHP. The PRAC serves the states of California, Hawaii, and Nevada by:

- providing CHP education and outreach services (e.g. with the PRAC website at http://www.chpcenterpr.org and through conferences and workshops);
- conducting "level 1" CHP project screenings for promising potential projects;
- developing CHP baseline assessment and action plan reports for each state in the region, to be periodically updated and improved; and
- developing example project profile "case studies" for CHP system projects in the Pacific region.

For the Hawaii CHP market specifically, the PRAC would like to work with CHP stakeholders and potential "end-users" in the state to further develop CHP resources for the state. As this report makes clear, Hawaii is a unique state with special conditions and concerns related to its energy sector. The PRAC hopes to work with local groups among the islands to develop energy strategies for Hawaii that are technically and economically sound, and also environmentally and culturally appropriate.

3. The Hawaii CHP Landscape

Key organizations for the Pacific Region CHP market include equipment suppliers and vendors, engineering and design firms, energy service companies, electric and gas utility companies (both "investor owned" and "cooperative"), research organizations, government agencies, and other non-governmental organizations. Appendix A of this report includes a database of contact information for key organizations involved in the CHP market. The organizations listed in the appendix are those that have responded to requests for contact information. As subsequent revisions of this report are made, the PRAC expects the contact database to become more complete and comprehensive.

Hawaii's electrical services are provided by one investor-owned utility company (known as an "IOU") and one island cooperative. There is currently one provider of electric services on each island that supplies power to the majority of homes and businesses. Hawaii Electric Light Company (HELCO) is the provider of electric utility services on the island of Hawaii. Maui Electric Company (MECO) is the provider of electric utility services on the islands of Maui, Lanai, and Molokai. Hawaiian Electric Company (HECO) is the provider of electric utility services on Oahu and is the parent company of MECO and HELCO. Kauai Island Utility Cooperative (KIUC) is the provider of electric utility service on the island of Kauai. The Gas Company provides utility gas services throughout the state of Hawaii.

There are many challenges facing Hawaii's electricity system that may prove to be addressable with CHP, but the most important is the need to diversify sources of generation. The majority of Hawaii's economy is based on military and tourism. This makes electricity reliability critical, and the need to quickly recover from an electrical outage essential.

Historical experience has shown that the most vulnerable part of Hawaii's electric power system is the distribution system, followed by the generation system that also introduces key vulnerabilities. In 1992, Hurricane Iniki devastated the electricity distribution system on the island of Kauai, which slowed their economy's ability to recover from the devastating storm. In 2006, a large earthquake disrupted power on all of the islands. It took nearly 19 hours for power to be restored for all but 2,200 of HECO's 291,000 customers on Oahu (Segal, 2006). Significant facilities, such as Honolulu International Airport, were forced to remain inoperable until electricity was restored. HECO uses diesel generators to start larger steam-generating units that power up the grid in the event of a blackout, a process that can take four to eight hours with the current generators. Additional generating units could save several hours in the first phase of a blackout restoration by bringing an initial increment of power online faster (Segal, 2006).

Table 1: Electricity Generation Fuel Mix Among the Islands (2005 Calendar Year)

Fuel Sources	HECO (Oahu)	HELCO (Hawaii)	MECO (Maui, Molokai, and Lanai)	All HECO (HECO, HELCO, and MECO)	KIUC (Kauai)
Oil	77.30%	78.10%	92.80%	79.30%	88%
Coal	18.60%		1.60%	14.30%	
Biomass (includes waste-to-energy)	4.10%		4.50%	3.70%	10%
Geothermal		18.10%		2.10%	
Hydro		3.30%	1.20%	0.50%	2%
Wind		0.50%		0.10%	
Total	100%	100%	100%	100%	100%

Sources: DBEDT, 2000; HECO, 2007

Table 1 presents the fuel mix for the major Hawaiian islands by utility service territory, and for HECO as a whole. For HECO, the percentage of fuels used to produce electricity is based on the amount of electricity generated by the HECO family of companies and the amount of purchased from independent power producers in 2005. As shown in the table, the islands are strongly dependent on oil for electricity production, with approximately 80% of the electricity generated from oil. Coal supplies an additional 13-14%, making fossil fuels responsible for over 90% of electricity generation. Geothermal is significant on the Big Island of Hawaii, but only amounts to a few percent of overall generation for the state.

Hawaii's electricity system is unique in that it is made up of six small, isolated electricity systems rather than a vast grid spanning thousands of miles as is common on the mainland. While this setup does have some advantages it also means that line losses are high because of transmission and distribution constraints. Additionally, the price paid by utility customers for electricity has been trending upward in Hawaii, as it has elsewhere. The heavy reliance on imported oil for electricity generation (and for transportation) makes Hawaii's economy highly vulnerable to the fluctuations in the world oil market. In recent years, oil prices have risen significantly due to rising demand, interruptions in supply (e.g. from Iraq), and other factors. The rise in petroleum prices is a major contributor to the rise in electricity costs, since fuel cost adjustments are added to the rate set periodically by the Public Utilities Commission.

Growing demand in Hawaii continues to require additional generation. Since there are no naturally occurring sources of petroleum or natural gas, the state has been forced to continue to import all of its oil and coal, with synthesis gas and LPG produced locally, for the most part, from refineries in the state. This is the primary reason Hawaii has the highest statewide average cost of electricity in the U.S.

Residential customers on Oahu paid $0.09 per kilowatt-hour in 1991, but that price has risen to about $0.20 as of January 1, 2007. Maui residential customers are now paying an effective rate of $0.28/kWh. Customers on the island of Hawaii pay $0.31/kWh, while those on Kauai, Lanai, and Molokai pay about $0.33-.34/kWh. Commercial electricity rates are also comparatively high in Hawaii. The following table shows current commercial and residential rates for the HECO companies, including "blended" rates for customer classes where electricity demand and energy charges are billed separately.

Table 2: Commercial and Residential Electricity Rates for the HECO Companies

Rate Schedule	**Average Cents per Kilowatt-Hour**				
	HECO	**HELCO**	**MECO (Maui)**	**MECO (Molokai)**	**MECO (Lanai)**
Residential	20.06	31.03	27.67	33.95	32.51
"P" Large power use businesses	15.73	25.64	24.47	29.83	28.80
"J" Medium power use businesses	17.50	28.42	27.16	33.96	34.79
"G" Smaller power use businesses	21.20	36.00	30.23	41.70	35.62
"H" Commercial cooking, heating, air conditioning & refrigeration	17.48	29.35	27.27	31.75	31.67
"F" Street lights (City & State)	18.22	29.44	25.30	32.03	31.14

Source: HECO, 2007a

4. Overview of CHP Installations in Hawaii

The Pacific region has several hundred 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. (EEA) database of CHP installations in Hawaii shows a total of 30 sites. This total is not exactly correct because some of the older installations in the database may not be currently operational, and because the database is not comprehensive with regard to new installations. PRAC is working with EEA to update the database and improve its accuracy.

Table 3 shows a breakdown of the CHP sites by Pacific region state, along with additional data for the overall electricity generation in each state. Hawaii currently has approximately 500 MW of CHP capacity, compared with over 9 GW in California and 300 MW in Nevada. The average capacity of Pacific region CHP installations is 10.7 MW, and 55% of the CHP capacity is in large industrial systems of 50 MW or greater (Hedman, 2006). CHP systems in the western states of California, Hawaii, Nevada, and Arizona are estimated to be saving more than 370 trillion BTUs of fuel and 50 billion tons of CO_2 emissions per year, compared with the conventional generation they have replaced (Hedman, 2006).

Table 3: Electricity Generating Capacity and CHP Installations in the Pacific Region

	Hawaii	California	Nevada
Retail Customers (1000s)	435	13,623	981
Generating Capacity (MW)	2,267	56,663	6,856
Generation (Million MWh)	12	184	32
Retail Sales (Million MWh)	10	235	29
Active CHP (MW)	544	9,121	321
CHP Share of Total Capacity	24.0%	16.1%	4.7%

Source: Hedman, 2006, based mostly on data from EIA, 2002

Recent CHP installations include a CHP unit at the Grand Wailea Resort Hotel and Spa in Wailea, Maui, which became operational in December 2002. This customer-sited installation has helped the utility and its customers assess CHP as an emerging distributed generation technology. The City and County of Honolulu has been involved with landfill gas-to-energy project in Kailua, although the project has been terminated. Requests for proposals are being developed for two wastewater treatment plants that will include CHP utilizing biogas.

5. Current Economic Status of CHP Systems in Hawaii

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 4 below presents key characteristics of reciprocating engines, gas turbines, and microturbines. Fuel cells are an emerging CHP technology with higher capital costs but also higher operational efficiencies and very low emissions.

Table 4: CHP System Characteristics
(From the Combined Heat & Power Resource Guide and adjusted for Hawaii where noted)

Reciprocating IC Engines	**Capacity Range (kW)**	**100 – 500**	**500 – 2,000**
	Electric Generation Efficiency, % of LHV of Fuel	24 – 28	28 – 38+
	Installed Cost, $/kW (with Heat Recovery)	Up to 3,500[a]	Up to 3,000[a]
	O & M Costs, $/kWh	0.025[a]	0.025[a]
Gas Turbines	**Capacity Range (kW)**	**1,000 – 10,000**	**10,000 – 50,000**
	Electric Generation Efficiency, % of LHV of Fuel	24 – 28	31 – 36
	Installed Cost, $/kW (with Heat Recovery)	1,500	1,000
	O & M Costs, $/kWh	0.015	0.012
Micro-turbines	**Capacity Range (kW)**	**100 – 400**	
	Electric Generation Efficiency, % of LHV of Fuel	25 -30	
	Installed Cost, $/kW (with Heat Recovery)	2,000	
	O & M Costs, $/kWh	0.015	

Notes:
[a] Estimate adjusted for Hawaii installations.

Additional CHP system equipment includes electrical controls, switchgear, heat recovery systems, and piping for integration with building heating, ventilation, and air conditioning (HVAC) systems. These systems use waste heat generated by the prime mover directly to provide hot water for commercial buildings and hospitals, assist boilers in producing steam for industrial processes, and/or to drive absorption or adsorption chillers to provide cooling. Piecing these HVAC systems together, however, has high costs associated with buying, shipping, and assembling equipment from a large number of different manufacturers. Hawaii's long distance from mainland manufacturers magnifies this effect in ways not experienced in other states. In order for CHP to become more economically viable, there is a need to integrate HVAC systems with the prime mover to achieve footprint, cost, and reliability advantages over conventional "pieced together" systems.

The early adopters of CHP in Hawaii are in the commercial sector, and especially resort hotels. Commercial buildings have a relatively consistent annual energy use profile associated with the moderate climate in Hawaii, with about a 20% higher energy consumption during the hottest months of July – October (Competitive Energy Insight, Inc. 2004). The relatively low thermal loads for office buildings make at best a marginal economic case for retrofitting a building for CHP, especially on Oahu.

In contrast, the Kauai Marriott CHP system, which will tri-generate electricity, hot water, and cooling, is expected to save the resort about $706,000 per year (PERC, 2006). These cost savings are expected because of three beneficial conditions: more displaceable thermal loads, more electric chiller loads, and higher electricity prices. Resorts have a much higher and more consistent demand for hot water because they have a much higher ratio of showers and washing machines per occupant than typical office buildings. Simultaneously they also have much higher cooling demands than office buildings, which are often sealed much better than resorts.

6. Summary and Status of CHP Policy Issues

Important policy issues for CHP include utility interconnection procedures, utility rate structures including standby charges and exit fees, and economic incentive measures. An overview of these CHP/DG policy areas for the Hawaii market is provided below.

<u>Access and Interconnection Rules (Rule 14)</u>

Distributed generation/interconnection is an evolving, “work in progress” in Hawaii. Hawaii has established both simplified interconnection rules for small renewables and, more recently, separate rules for all other DG. Simplified interconnection and net metering are available for solar, wind, biomass, and hydroelectric systems up to 50 kilowatts (kW) in capacity. This limit was raised from 10 kW to 50 kW in 2005 by SB 1003.

The state’s major electric utility, HECO, uses a set of simple “how-to” interconnection guidelines. HECO also uses a simple, two-page net-metering agreement. A manual, lockable disconnect is required for net-metered systems. There are no additional liability-insurance requirements, and a provision for mutual indemnification is included. The state’s only other electricity provider, KIUC, has proposed a similar set of interconnection rules. These rules are currently under review by the Hawaii Public Utilities Commission (HPUC).

The interconnection of DG systems in Hawaii is generally governed by Rule 14, which was instituted by HPUC Order No. 19773. This order was issued in 2002 and modified in 2003. Rule 14 includes by reference the utilities’ technical interconnection standards (Appendix I), interconnection agreement (Appendix II) and interconnection procedures (Appendix III). The rules cover all DG technologies.

Appendix I of Rule 14 states that a manual disconnect is required for all installations and a dedicated transformer may be required by the utility depending on the short circuit contribution of the DG device. Interconnection with network distribution systems (as opposed to radial systems) is addressed, although it is unclear when additional studies would be needed to address such interconnections.

In October 2003, the HPUC initiated a new proceeding (Docket No. 03-0371) to review and improve the state’s DG interconnection rules. The HPUC released its Decision and Order on 03-0371 on January 27, 2006. The decision, numbered 22248, outlines policies for several aspects of distributed power generation in Hawaii. These include conditions under which utilities can participate in DG projects, the role of DG in the state's integrated resource planning process, DG interconnection procedures, and utility rate design including standby charges.

Rates, Standby Charges and Exit Fees

Hawaii PUC Decision and Order No. 22248 states, among other things, that all the parties agree that standby and backup charges should be cost-based. However there was no general agreement on what those costs are, and the record on the subject was not sufficiently developed for the commission to design actual standby rates. Therefore, the PUC requires each utility to establish, by proposed tariff for commission approval, standby rates based on unbundled costs associated with providing each service. In response, the HECO submitted their proposed amendments to Tariff No. 1, which contains the proposed amendments to their existing standby rates and provisions on August 28, 2006. KIUC submitted similar proposed amendments on November 27, 2006.

These attempts by the utilities to raise standby charges have not yet succeeded, and have drawn much controversy, largely because they have not been supported by recent cost of service studies. The KIUC proposal was replaced by a "Revised Standby Proposal" that was reached unanimously among the various parties and filed on November 30, 2007. This agreement limited standby charges to $5 per kW/month through 2014 but with a limit of a total of 5 MW of qualified projects. In contrast, the rates proposed by KIUC in 2006 would have raised the standby charge of $5 per kW-month to over $30 per kW-month, and the rates proposed by HECO would have raised standby charges on all of the islands served by the HECO utilities, including adding standby charges on Oahu and Maui where there currently are no standby charges. If ultimately approved, these dramatic rises in standby fees would make most commercial CHP projects in Hawaii all but economically infeasible.

Unfortunately, on July 24, 2008, an order by the Hawaii PUC altered this agreement by allowing for the expiration of the $5 per kW/month during the course of KIUC's next general rate case, expected by about the end of 2011. Instead of six years of time for currently planned CHP on Kauai to be assured of the current standby charges, that time has now been effectively cut to three years. The consequences of this revised order are large, where for example the Kauai Marriott with a proposed 810 kW project could stand to see its standby charges rise from $4,050 per month under the current regime to $25,312 per month under the rates proposed by KIUC in 2006, or by an amount in excess of $250,000 per year.

The Kauai Marriott and Bluepoint Energy filed motions for reconsideration of the July 24th order with filings under docket No. 2006-0498 on July 3, 2008 (for example, see Gorak [2008] for the Kauai Marriott filing). However these motions were then denied by the PUC on October 8, 2008, saying that they had not "met their burden of establishing that the commission's Decision and Order is unreasonable, unlawful, or erroneous" (Hawaii PUC, 2008). This means that the standby charge issue will be taken up in the next KIUC general rate case

In the HECO service territory, comparing the demand charges alone from the proposed tariffs on a per kilowatt-hour basis to the existing average rates advertised by HECO on its web site for the same customer classes J and P, no customer could reasonably afford to pay for standby service as proposed and pay its own system costs on self-generation and interconnection. This is because the monthly billing demand charge would be determined by multiplying the applicable rate schedule billing demand rate ($/kW) by the standby "monthly billing demand." The standby "monthly billing demand" would be determined by the lower of either the actual metered demand during the current billing period, or the highest metered demand during the previous 11-month period (if the customer's peak metered demand during the previous 11-month period is greater than the contracted standby demand).

If, however, the customer's peak metered demand during the previous 11-month period is less than or equal to the contracted "standby demand," the standby "monthly billing demand" would be zero. This "demand ratchet" method of determining standby rates is both onerous and punitive to customers who install CHP. Additionally, a six-month reservation demand charge is applied for early termination of the standby contract by a customer. Taken together these provisions are designed to be sufficiently punitive that no one would enter such a contract.

The situation in Hawaii with regard to utility rates is thus highly tenuous, and should be watched carefully by those that have an economic or environmentally-based interest in seeing progress in the market penetration of CHP in Hawaii.

<u>Greenhouse Gas Emissions Legislation</u>
On May 3, 2007, Hawaii passed *House Bill 226* (Thielen) the "Global Warming Solutions Act of 2007." The bill requires the state to identify all sources of greenhouse gases, regulate greenhouse gases as a pollutant, and reduce emissions to 1990 levels by 2020 (and further thereafter). The legislation requires the state to establish a task force to prepare a regulatory scheme and work plan "for implementing the maximum practically and technically feasible and cost-effective reductions in greenhouse gas emissions from sources or categories of sources of greenhouse gases to achieve the statewide greenhouse gas emissions limits by 2020" (*HB 226*). Depending on the details of the regulatory scheme that gets developed, this legislation may provide an incentive for advancing the CHP market in the state because of the greater energy efficiency and reduced emissions that CHP systems can provide relative to conventional grid power.

<u>Hawaii-DOE Clean Energy Initiative</u>
More recently, on January 31, 2008, Hawaii's Gov. Lingle signed a memorandum of understanding with U.S. DOE for the "Hawaii-DOE Clean Energy Initiative." The goal of this initiative is to decrease energy demand, accelerate the use of renewable and indigenous energy sources in Hawaii, and establish a target of 70% renewable energy in Hawaii by 2030 (DBEDT, 2008). This would go well beyond the current RPS goals in Hawaii of 10/15/20% of renewable energy in the electricity sector by 2010/2015/2020. Efforts are currently underway to further assess Hawaii's renewable resource potential, and to determine the most promising pathways for achieving this very ambitious clean energy goal.

<u>Economic Incentive Policies</u>
Hawaii currently does not have a buy-down incentive or state tax incentive for CHP system installation or operation. The available incentives are those available at the federal level, including the investment tax credit that is currently available for the installation of microturbine systems (see Section 8 below).

7. The Market Potential of CHP Systems in Hawaii

Hawaii is an exciting and economically attractive market opportunity for CHP. In general, the economic conditions for CHP in Hawaii are aided by high prevailing electricity prices, but hindered by relatively high gas prices. All of Hawaii's natural gas is synthetic natural gas (SNG)[2]

[2] The Gas Company's SNG consists of 80% methane, 10% hydrogen, 5% butane, and 5% carbon dioxide.

derived from naphtha. The SNG is provided through The Gas Company's utility business, which is regulated in its rate offerings by the state PUC.

The Gas Company also sells regulated and non-regulated propane to those customers without access to SNG. Propane prices in Hawaii are determined by The Gas Company's procurement costs, and are closely tied to the price of oil that is imported into the state. The Gas Company purchases its propane or "liquefied petroleum gas" (LPG) from two local refineries as well as offshore suppliers. This LPG, along with SNG, is used to meet the needs of their customers. There are no naturally occurring sources of petroleum products or natural gas in Hawaii.

In order to support the adoption of CHP, The Gas Company offers its non-utility and utility propane customers who install CHP dedicated propane gas rates. These rates are specifically designed to assist CHP customers by lowering operating costs and managing pricing risk

The economics of CHP are island and site specific. The economics of "third party ownership" are stronger on outer islands where electricity costs are higher than on Oahu. On Oahu, there is a strong preference for sites with substantial thermal uses. On Maui and the Island of Hawaii, the economics appear to be very attractive subject to system optimization, efficient design, and risk management. On Kauai, the economics appear to be compelling due to the very high costs of electric energy on the island.

In many instances diesel appears to be the most economic fuel for CHP on the outer islands, where SNG is not available. However, this conclusion is subject to the important considerations of transportation, storage, permitting and environmental benefits offered by gaseous/liquefied gas fuels such as SNG or propane, which for many sites may prevail over the fuel cost difference. It is important to note that both diesel and gaseous/liquefied gas fuels can exhibit attractive returns for host, third party, or utility investment in power projects, especially on the outer islands (Competitive Energy Insight Inc., 2004).

The major Hawaii utilities have made projections regarding the potential market penetration of CHP in Hawaii over the period of 2003 through 2012. For the HECO group of companies, over 80 MW of CHP potential were forecast over that ten-year period (Competitive Energy Insight Inc., 2004).

We note, however, that the PUC has recently placed restrictions on utility ownership of CHP, causing HECO to withdraw their ownership program application. This means that HECO will probably only look at ownership on a rare case-by-case basis that meets the PUC guidelines. With these new PUC restrictions, future CHP developments in Hawaii are expected to be performed primarily by non-utility entities. Approximately half of the 80 MW of CHP potential forecast by HECO was in the form of utility-owned projects, suggesting that based on this PUC decision the likely penetration of CHP is likely to be more like 40-50 MW through 2012 under current conditions.

8. Summary of CHP System Financial Assistance Programs

Federal investment tax credits for CHP system installation have been included under various energy policy legislation proposals in recent years. At present, investment tax credits are available for fuel cell and microturbine installations, but not for CHP systems more generally. A broader CHP federal investment tax credit of 10% was proposed under the 2005 Energy Policy Act, but was cut in the final conference meeting at least partly due to a shift in Office of Management and Budget methodology that showed the program to be a net resource consumer instead of a revenue generator. The USCHPA is currently working on a new proposal for a federal CHP investment tax credit, with either a 20 MW or 50 MW cap on qualifying system size.

For energy end-users in Hawaii that are interested in potential CHP projects, both the PRAC and the U.S. EPA offer services to perform initial project screenings to determine CHP system feasibility, optimal system type and size, and potential system economics. The PRAC feasibility studies are conducted by San Diego State University, with a team of experts deployed to the site to collect equipment and energy use data and a year of utility bills. The CogenPro software package is then used to determine optimal system sizing and approximate system economics. Project screenings are offered by the PRAC on either a no-charge or cost-shared basis, depending on the nature of the potential installation.[3]

The U.S. EPA also offers initial CHP project screening services. Interested parties can contact EPA staff, and if qualified, can then fill out a data submittal form that is available on the U.S. EPA CHP Partnership website. They will then receive a report with the findings from the "Level 1" screening analysis.[4]

9. Action Plan for Advancing the CHP Market in Hawaii

The key barrier that the CHP market in Hawaii faces at the present time is the prospect of new and burdensome standby charges that have been recently proposed by the utilities. The rates proposed by the utilities appear to be unjustified by the factual record and will unduly discriminate against customers who install on-site generation relative to other similarly situated customers. These proposed rates are, in our opinion, likely to prevent customers from installing on-site generation where they otherwise might, and in fact to kill some projects that are currently in the pipeline and where significant investments have already been made. We suggest that the Hawaii PUC reject the proposed tariffs in their entirety and require the companies to resubmit tariffs that are fair, balanced, and non-discriminatory to both those who do and who do not choose to self-generate their electrical power.

Potential longer-term barriers to CHP in Hawaii are: 1) regulatory hurdles that add difficulty and cost to developing and interconnecting projects, 2) an "uneven playing field," that does not recognize and incentivize the environmental and grid benefits of DG/CHP, and 3) standards, codes, permitting, and zoning rules that are predominantly based on and biased toward central power station generation. Since utilities make a return on electricity sold, their incentive is to sell more electricity and not to conserve or partially or fully lose customers through customer-sited generation projects. The utilities are also allowed to pass all fuel costs through to the consumer, so the utility has no incentive to invest in hedging practices such as CHP.

Therefore, it is up to policy makers to reduce the asymmetry between the utility and its customers or competitors. States such as California, Connecticut, and New York have reduced this asymmetry by enacting progressive standards, codes, permitting, and zoning practices that set clear guidelines for the utilities to follow with respect to CHP installations. California and New York were among the first states to develop interconnection standards, in the 1990s, and now have well-developed rules to complete interconnection processes in a timely fashion. For example, New York has an 11-step process from "initial communication from the potential applicant" to "final acceptance and utility cost reconciliation" that is helping to standardize and

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[3] For more details on PRAC CHP project feasibility screenings, please visit http://www.chpcenterpr.org or contact Dr. Asfaw Beyene directly at abeyene@rohan.sdsu.edu.
[4] For more details, please visit: http://www.epa.gov/chp/project_resources/tech_assist.htm

expedite interconnection procedures (New York State Public Service Commission, 2007). California and Connecticut have significant incentive programs for DG, in the form of capital cost "buy-downs" and low-interest loans, that are helping to expand the DG/CHP markets in those states.

Thus, Hawaii does not have to "re-invent the wheel" but rather examine what other states are doing and adapt the most successful of the policies that are also appropriate for Hawaii's unique market. These three states have proven themselves to be pioneers in fostering clean energy and we would like to see Hawaii join their energy leadership with policies and regulations in support of clean DG/CHP.

Our recommendations to advance the CHP market in Hawaii include the following:

<u>1. Issue HPUC policy directives to reject the proposed tariffs in their entirety and require the utilities to resubmit tariffs that are fair, balanced, and non-discriminatory to both those who do and who do not choose to self-generate their electrical power</u>
The dramatic increase in standby charges for DG projects proposed by HECO and KIUC in 2006, and then later withdrawn, do not appear to be supported by a fair assessment of what these charges should be. It is reasonable to assess reasonable levels of charges for DG projects to make sure that costs are not shifted from customer generators to other customers, as noted in HPUC Order 22248:

> "To ensure that only economic distributed generation projects are developed, and that there is no cost shifting from the customer-generator to other customers or to utility shareholders, utility-incurred costs shall be allocated properly so that those costs that benefit the distributed generation project are borne by the project. This principle is applied to interconnection costs, standby and backup service costs, and unrecovered utility costs, as described above." (HPUC Order 22248)

The standby charges proposed by HECO and KIUC would appear to go well beyond this level, to the point of being discriminatory to DG projects and to customer generators. We therefore recommend that the standby charge proposals be rejected and that the utilities be directed to develop such rates in a transparent and cost-of-service based manner, supported by careful and clear analysis to that effect, such that their appropriateness can be carefully studied and verified.

<u>2. Enact legislation that provides relief from regulatory hurdles that add difficulty and cost to developing and interconnecting projects</u>
HPUC Docket 03-0371 did much to advance DG/CHP policy in Hawaii, in terms of broadly outlining important policy areas and issuing general orders to encourage the development of economically beneficial DG projects in the state. However, additional legislation is required to improve the DG interconnection process and to remove remaining regulatory hurdles associated with planning, permitting, and interconnecting DG projects. Streamlined procedures could be developed that would reduce the costs and time required to implement projects, and this would assist the further development of the DG/CHP market in Hawaii.

<u>3. Institute a more even playing field, that recognizes and incentives the environmental and grid benefits of DG/CHP</u>
DG and CHP systems can provide significant environmental and utility grid support benefits. These benefits should be considered in developing fair utility rate and standby chargers for DG projects, as well as potential incentive policies. While the extent of these benefits can by highly

variable depending on technology type, the end-use application, and the location within the utility grid, extensive previous research has led to the development of assessment tools and techniques that can evaluate the potential benefits of DG/CHP projects. These findings can then be used as a basis to recognize the actual benefits that individual projects can provide.

4. Encourage standards, codes, permitting, and zoning rules that are not biased toward central power station generation

Despite the progress made for DG development in Hawaii, through HPUC Docket 03-0371 and other developments, various codes, standards, permitting, and zoning rules are still subtly (or not so subtly) biased toward central power generation and away from DG/CHP. We recommend continued action to review these regulations and to systematically make them less biased, so that cost effective DG projects can fairly compete with central generation in meeting the state's growing needs for electrical power and heating/cooling.

5. Adapt the most successful of the CHP policies from other states to Hawaii's unique market

As noted in this report, states such as California, New York, and Connecticut have adopted policies to encourage the development of DG and CHP in ways that recognize the economic and environmental benefits that DG system implementation can provide. We recommend that Hawaii study these other state programs, and consider adopting elements of them that are appropriate for the state, given it's unique energy resource landscape and economic and environmental conditions.

6. Examine and consider implementing a research, development, and demonstration (RD&D) program for clean DG/CHP in Hawaii

Some states, such as California, have active RD&D programs for clean energy technologies to complement RD&D activities at the federal level. Hawaii conducts a limited amount of DG research through DBEDT, and has historically been successful in attracting federal funding particularly for hydrogen and fuel cell research. However the state could consider expanding these activities to develop a more robust and state-focused RD&D program for clean energy technologies. This could be funded through a modest "public goods charge" on energy sales, with funds administered by DBEDT for well-targeted RD&D activities with the ultimate goal of benefiting energy ratepayers in the state through improved energy efficiency, reduced emissions from energy production, and reduced costs of energy services. A state level program would allow Hawaii's specific needs and considerations to be the focus, as opposed to federal programs that are typically more generic and less likely to confer benefits directly to the residents of Hawaii.

10. Conclusions

Hawaii represents an attractive market opportunity for CHP due to a combination of economic conditions, strong growth in demand for energy services, and energy and environmental concerns. There currently is approximately 500 MW of CHP capacity in the state, although some of this capacity is represented by relatively old projects of which some may no longer be operational.

CHP economics in Hawaii are both island and site specific. On Oahu, projects can be attractive where there is a good use for thermal energy that matches the profile of electrical output. On the other major islands of Hawaii, Maui, and Kauai, economics are more attractive due to the very high cost of electrical power. Efficiently designed projects can easily be attractive on these islands.

The greatest immediate threat to the CHP market in Hawaii is the large increase in standby charges for CHP projects that are being proposed by the major island utilities. If these charges are implemented, CHP economics will be dramatically affected and may no longer be attractive except possibly in the very best settings. We hope that moving forward, changes in electricity tariff structures are made carefully and fairly, and in ways that do not preclude the important principle of customer choice with regard to the provision of electrical services for commercial and industrial sites in the state.

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2008 Combined Heat and Power Baseline Assessment and Action Plan for the Nevada Market

Final Project Report

September 30, 2008

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Table of Contents

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Executive Summary

The purpose of this report is to provide an updated assessment and summary of the current status of combined heat and power (CHP) in Nevada and to identify the hurdles that prevent the expanded use of CHP systems. This report has been prepared by the Pacific Region CHP Application Center (PRAC). The PRAC is a United States Department of Energy (DOE) and California Energy Commission[1] sponsored center to provide education and outreach assistance for CHP in the Pacific region of California, Nevada, and Hawaii. The PRAC is operated by the University of California – Berkeley (UCB), the University of California – Irvine (UCI), and San Diego State University (SDSU).

The information presented in this report is intended to provide:

- an overview of the current installed base of CHP systems in Nevada;
- a summary of the technical and economic status of key CHP system technologies;
- a summary of the utility interconnection and policy environment for CHP in Nevada;
- an assessment of the remaining market potential for CHP systems in Nevada;
- an "action plan" to further promote CHP as a strategy for improving energy efficiency and reducing emissions from Nevada's energy system; and
- an appendix of contacts for key organizations involved in the Nevada CHP market.

<u>The Nevada CHP Landscape</u>

Nevada's electrical and natural gas services are primarily provided by investor-owned utility companies (IOUs), with additional services provided by rural cooperatives. The major IOUs – providing a combined total of over 90% of the electricity used in the state – are Nevada Power Company and Sierra Pacific Power Company. These two companies merged in 1999 and now are jointly held by Sierra Pacific Resources. Natural gas is supplied in Nevada by Southwest Gas Company and Sierra Pacific Power Company.

Nevada currently has approximately 320 MW of installed CHP capacity, which contributes to 7% of the state's electricity generation. Although only a fraction of the population and economy of the Pacific region, Nevada has significant opportunities for reducing greenhouse gas emissions through the deployment of CHP in their buildings sector, particularly in the growing hospitality industry.

CHP systems in the western states of California, Hawaii, Nevada, and Arizona are collectively estimated to be saving more than 370 trillion BTUs of fuel and 50 billion tons of CO_2 emissions per year, compared with the conventional generation they have replaced (Hedman, 2006).

<u>Technical and Economic Status of Key CHP Technologies</u>

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 ES-1 below presents a summary of key characteristics of each of these types of generators.

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[1] Hereafter, the California Energy Commission is referred to as "the Energy Commission."

Table ES-1: 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	Up to 85% (AE)	Up to 75% (AE)	Up to 75% (AE)	Up to 75% (AE)	Up to 90% (AE)
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 (GTI)	$0.007-0.015/kWh (GTI)	$0.005-0.01/kWh
Maintenance Interval	5,000-8,000 hrs	ID	40,000 hours	ID	ID

Source: Data from Energy Commission, 2007, except Gas Tech. Institute for O&M costs as noted by "GTI" and "AE" for author estimates

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.

Summary and Status of CHP Policy Issues in Nevada

Important policy issues for CHP include utility interconnection procedures, utility rate structures including "standby charges" and "exit fees," and economic incentive measures. An overview of these CHP/DG policy areas for the Nevada market is provided below.

Grid Access and Interconnection Rules -- On December 17, 2003, the Public Utilities Commission of Nevada (PUCN) adopted interconnection rules – known as Rule 15 -- for customers of Nevada Power and Sierra Pacific Power. The provisions of Rule 15 are consistent with California's interconnection standards

(Rule 21), IEEE 1547 rules, and the model interconnection agreement of the National Association of Regulatory Utility Commissioners (NARUC). Rule 15 specifies interconnection procedures for the DG systems of up to 20 MW in size. Somewhat controversially, Rule 15 allows utilities to charge customer-generators for past fuel and purchased-power expenses in their tariffs (DSIRE, 2007). The December 2003 agreement also revised Nevada's net metering standards for renewable energy systems including biomass-powered ones. The rules revised the net-metering program to allow systems of up to 150 kW to be net metered, up from a previous limitation of 10 kW (DSIRE, 2007a).

Market Incentives for CHP System Installation - In contrast to states like California, which have been actively promoting the installation of CHP systems through incentive programs, Nevada does not yet have clear plans for promoting CHP technology. Nevertheless, the state has taken steps toward working with industry and recognizes the need to change interconnection rules so that distributed generation can be better accommodated (NSOE, 2005; ACEEE, 2006). Nevada does not currently offer funding or rate class exemptions for CHP. However, they have established environmental regulations and net metering standards, which now encourage the implementation of a wide range of distributed power sources, and could potentially include CHP in the future.

Energy Portfolio Standard - As part of its restructuring efforts, Nevada established its Energy Portfolio Standard (EPS) in 1997. The PUCN administers the EPS and requires the two IOUs to obtain a certain fraction of their energy from renewable sources. The EPS was later revised in 2001 to require a scheduled portfolio increase of 2% every two years, hitting a maximum of 15% in 2013. In 2005, the EPS was amended once again under *Assembly Bill 3* (*AB 3*). Increases were raised to 3% every two years, reaching a maximum of 20% in 2015. The bill allows for the EPS to be met through renewable energy generation or credits and savings from efficiency measures. Also, *AB 3* requires that at least 5% of total electricity come from solar systems. Under the current standard, systems that quality for the portfolio include biomass, solar, geothermal energy, wind, and some hydro projects.

Net Metering Rules and Utility Rates - First introduced in 1997, net metering in Nevada allowed IOUs to meter renewable systems up to 30 kW. The rules were subsequent modified in 2001, 2003, and 2005 to allow to systems as large as 150 kW. Nevertheless, for units greater than 30 kW, customers are required to install their own meter. Moreover, the utilities can arbitrarily charge interconnection facility and demand fees. For units smaller than 30 kW, net excess generation (NEG) could be carried over to the next billing cycle indefinitely. Under utility terms for time-of-use rates, the excess generation would be added to the same time-of-use period of the subsequent months.

Governor's Energy Plan - The state of Nevada has provided relatively little policy or financial support for DG and CHP. However, the Governor's most recent comprehensive energy plan makes general pro-DG/CHP recommendations such as to make "incremental changes in tariffs to allow net metering and self-generation" and make "changes in tariffs and interconnection rules to accommodate distributed generation" (NSOE, 2005).

Energy Requirements for Government Buildings - Starting on July 1, 2007, Nevada will require that all public buildings sponsored or financed by the state must meet standards specified by the Leadership in Energy and Environmental Design (LEED) system (NRS 338.187). Technologies that earn LEED certification points include passive solar space heating, and renewable energy systems (including biomass and biogas), as well as a potential point or two for CHP systems more generally in the “innovation and design” category. In addition, the measure requires at least two constructed public buildings to meet the equivalent of LEED “silver” or higher over every two-year period.

Beyond these issues, a more general issue for Nevada is the controversial construction plans for future coal-fired power generation in the state, relative to other power-generation alternatives. A specific recent issue is the potential construction of the Ely Energy Center (EEC). Since proposed, the EEC has proven to be highly controversial and the project has recently been delayed over environmental concerns. This plant has been proposed to provide 1500 MW of generation capacity and potentially up to 2500 MW, with the first of two 750 MW units to be online by 2015 and the potential for two additional 500 MW units to be added in a future phase (Sierra Pacific Resources, 2008). Figure 1, below, shows the location of the proposed EEC and a new transmission line that would connect the facility to Las Vegas.

Figure 1: Proposed Ely Energy Center
(Source: Sierra Pacific Resources, 2008)

<u>The Market Potential of CHP Systems in Nevada</u>
The major lodging, resort, and casino sector provides Nevada with a significant opportunity to

implement CHP in higher-end hotels. The EPA estimates that about 10,000 hotels nationwide have energy demand profiles that can be efficiently met by CHP, and Nevada establishments have the highest average number of rooms in the country. Many existing sites in Nevada are eligible for conversion to CHP, and many more lodging units are expected to be built with the tourism and gambling industries expanding for the foreseeable future.

Other major industries include manufacturing, printing, and publishing. In 2003, the state gross product was estimated to be $88 billion according for the Bureau of Economic Analysis. Nevada is the fastest growing state in the country with 8.0% annual growth last year (Wachovia, 2006). The growth is largely driven by gains in the tourism and gaming industries, commercial and residential construction, and an influx of retirees.

EEA has recently completed a market assessment report for Nevada and Arizona that indicates that Nevada has a technical potential for 2,334 MW of additional CHP through 2020. EEA estimates that 1,792 MW of this potential is in existing facilities, and 1,216 MW of the potential is in new facilities that are expected to be built between 2005 and 2020. The total technical potential is reduced somewhat to arrive at the 2,334 MW figure, to avoid double counting in some applications where both traditional and cooling CHP opportunities were assessed. Table ES-2 below presents these technical potential estimates by existing and new facilities and the application (EEA, 2005a).

Table ES-2: EEA Estimate of Nevada CHP Technical Market Potential by Application

CHP Type	**MW Capacity**
Existing Facilities (MW)	
Industrial – On Site	316
Commercial -- Traditional	669
Cooling CHP	801
Large Industrial – Export	0
Resource Recovery	6
New Facilities (2005-2020) (MW)	
Industrial – On Site	32
Commercial/Institutional	518
Cooling CHP	666
Net Total Technical Potential*	**2,334**

Source: EEA, 2005a
Note: *Total adjusted to avoid double counting some applications that are analyzed in both traditional and cooling CHP categories

Summary of CHP System Financial Assistance Programs

There are no specific state incentive programs for CHP system installation in Nevada. The state's net metering program provides a form of incentive for biomass-based CHP projects, of 150 kW or less, by allowing export of extra power to the grid that can then be withdrawn at a later time. The main applicable financial assistance programs include federal tax programs, including the microturbine and fuel cell system tax credits, and CHP project screening services that are available on a limited basis from the PRAC and the U.S. Environmental Protection Agency.

Action Plan for Advancing the CHP Market in Nevada

The final section of this report presents a series of ideas for further advancing the CHP market in Nevada. Key recommendations include:

1. Consider legislation to provide capital cost buy-down incentives and/or low-interest loan programs for CHP systems, potentially with a performance-based component;

2. Institute co-metering for CHP systems to allow for power export to the grid with rules for power purchase from CHP system owners based on wholesale power prices plus consideration for their T&D, grid support, and GHG reduction benefits;

3. Encourage the use of CHP as a power reliability measure for critical need applications such as refineries, water pumping stations, emergency response data centers, etc.;

4. Include DG/CHP in the state integrated resource planning process; and

5. Consider PUCN direction to the Nevada utilities to develop more consistent and favorable utility tariff structures for CHP customers.

See Section 9 of the main text of this report for further elaboration of these "action plan" concepts.

Conclusions

Nevada is the highest growth state in the country in terms of population and energy demand growth. The state has relatively little CHP installed at present, with only a few hundred MW of installed capacity. The hotel and casino sector represents a particularly attractive sector for CHP systems, and one that is growing rapidly. Additional market potential includes the hospital, grocery, and wastewater treatment sectors, and some remaining mining and industrial sector opportunities.

Further DG/CHP policy development in Nevada could be important to furthering CHP opportunities in the state. Some basic elements are in place, in terms of interconnection standards for systems of up to 20 MW in size and net-metering programs for renewable systems. Additional programs to provide financial support for CHP system installation – to encourage them for their energy efficiency, economic, and environmental benefits – and to consider further development of CHP compared with other alternatives in the context of the state IRP process, would be helpful to further develop the CHP market in Nevada.

1. Introduction

The purpose of this report is to assess and summarize the current status of combined heat and power (CHP) in Nevada and to identify the hurdles that prevent the expanded use of CHP systems. This report has been prepared by the Pacific Region CHP Application Center (PRAC). The PRAC is a United States Department of Energy (DOE) and California Energy Commission[2] sponsored center to provide education and outreach assistance for CHP in the Pacific region of California, Nevada, and Hawaii. The PRAC is operated by the University of California – Berkeley (UCB), the University of California – Irvine (UCI), and San Diego State University (SDSU).

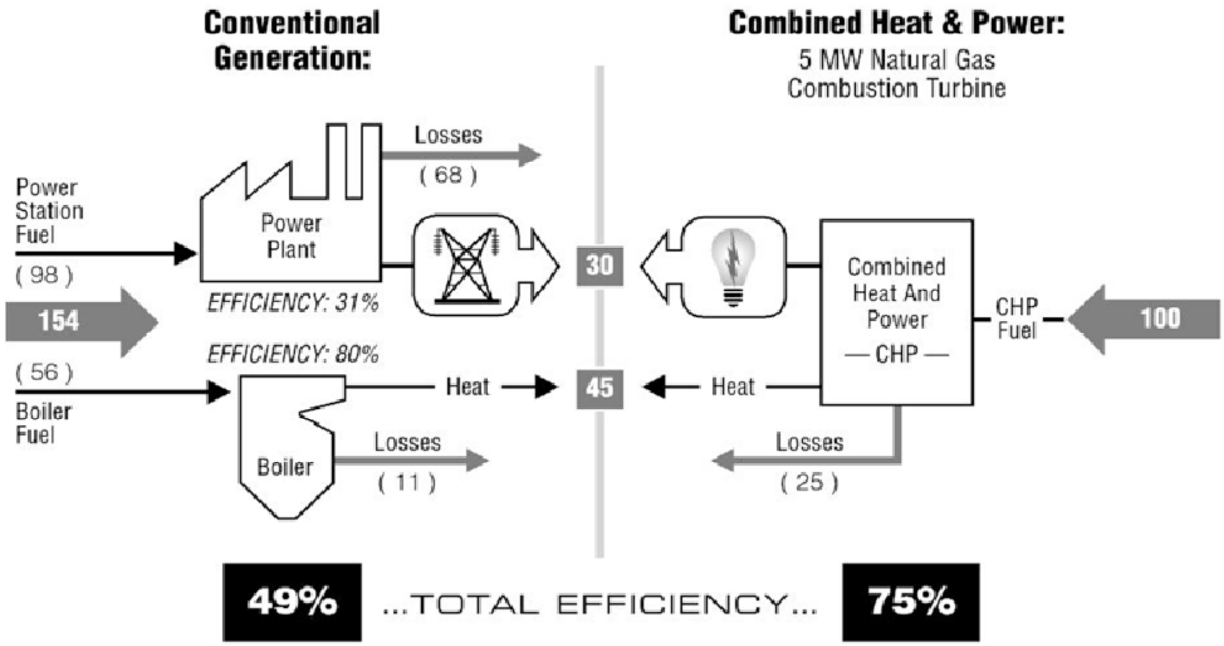
The information presented in this report is intended to provide:

- an overview of the current installed base of CHP systems in Nevada;
- a summary of the technical and economic status of key CHP system technologies;
- a summary of the utility interconnection and policy environment for CHP in Nevada;
- an assessment of the remaining market potential for CHP systems in Nevada;
- an "action plan" to further promote CHP as a strategy for improving energy efficiency and reducing emissions from Nevada's energy system; and
- an appendix of contacts for key organizations involved in the Nevada CHP market.

As a general introduction, CHP is the concept of producing electrical power onsite at industrial, commercial, and residential settings while at the same time capturing and using waste heat from electricity production for beneficial purposes. CHP is a form of distributed generation (DG) that offers the potential for highly efficient use of fuel (much more efficient than current central station power generation) and concomitant reduction of pollutants and greenhouse gases. CHP can also consist of producing electricity from waste heat or a waste fuel from industrial processes.

The following figures depict the manner in which CHP systems can provide the same energy services as separate electrical and thermal systems, with significantly less energy input. As shown in Figure 1, to provide 30 units of electricity and 45 units of heat using conventional generation would require energy input of 154 units. A typical CHP system using a 5 MW combustion turbine could provide these same energy services with only 100 units of energy input, thereby saving net energy, cost, and greenhouse gas emissions.

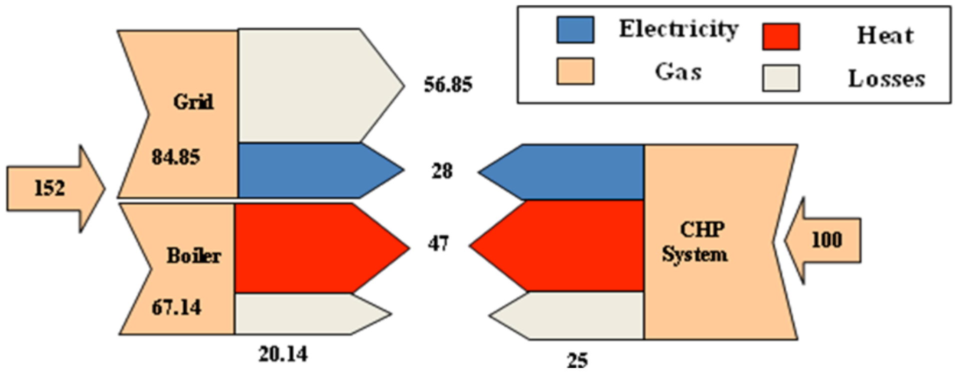
[2] Hereafter, the California Energy Commission is referred to as "the Energy Commission."



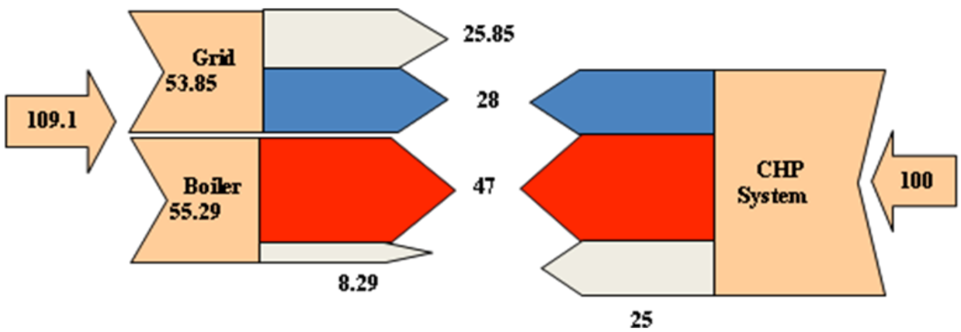
Source: Hedman, 2006

Figure 1: CHP Flow Diagram Based on 5 MW Combustion Turbine (generic energy units)

Figure 2 shows a more generalized depiction of the same concept. Compared with typical conventional generation, a present-day CHP system could provide the same electrical and thermal energy services with approximately two-thirds of the energy input. Even compared with a much advanced and more efficient combination of utility grid power and boiler technology in the future, the CHP system can still compete favorably.



Typical Conventional Generation



Advanced Technology for Grid and Boiler Technology

Figure 2: Generic CHP Flow Diagrams Compared with Typical and Advanced Conventional Generating Systems (generic energy units)

In addition to improving energy efficiency by capturing waste heat for thermal energy uses, CHP systems eliminate transmission and distribution (T&D) losses inherent in power produced from conventional centralized generation. These T&D losses are typically in the range of 7-11% of the amount of power delivered (Borbely and Kreider, 2001). CHP systems can also provide important grid "ancillary services" such as local voltage and frequency support and reactive power correction (i.e. "VARs"), and emergency backup power when coupled with additional electrical equipment to allow for power "islands" when the main utility grid fails.

Recognizing the potential of CHP to improve energy efficiency in the U.S., the DOE established a "CHP Challenge" goal of doubling CHP capacity from 46 GW in 1998 to 92 GW by 2010 (U.S. CHPA, 2001). As of 2006, there were an estimated 83 GW of CHP installed at 3,168 sites in the U.S., representing about 9% of total generating capacity in the country (Bautista et al., 2006). This suggests that the nation is generally on track to meet the DOE goal of 92 GW by 2010. However, new capacity additions appear to have slowed in recent years, with less than 2 GW installed in 2005 compared with about 4 GW in 2003 and 2004, and over 6 GW in 2001 (Bautista et al., 2006).

2. Report Purpose

As noted above, the purpose of this report is to assess the current status of combined heat and power (CHP) in Nevada and to identify the hurdles that prevent the expanded use of CHP systems. The report summarizes the CHP "landscape" in Nevada, including the current installed base of CHP systems, the potential future CHP market, and the status of key regulatory and policy issues. The report also suggests some key action areas to further expand the market penetration of CHP in Nevada as an energy efficiency, cost containment, and environmental strategy for the state.

An additional purpose of the report is to alert stakeholders in Nevada of the creation of the U.S. DOE "regional application centers" (or "RACs") for CHP. The PRAC serves the states of California, Hawaii, and Nevada by:

- providing CHP education and outreach services (e.g. with the PRAC website at http://www.chpcenterpr.org and through conferences and workshops);
- conducting "level 1" CHP project screenings for promising potential projects;
- developing CHP baseline assessment and action plan reports for each state in the region, to be periodically updated and improved; and
- developing example project profile "case studies" for CHP system projects in the Pacific region.

For the Nevada CHP market specifically, the PRAC would like to work with CHP stakeholders and potential "end-users" in the state to further develop CHP resources for the state. Nevada is a unique state with special conditions and concerns related to its energy sector. The PRAC hopes to work with local groups in the state to develop energy strategies for Nevada that are technically and economically sound, and also appropriate for the state's larger energy and environmental concerns.

3. The Nevada CHP Landscape

Nevada currently has approximately 320 MW of installed CHP capacity, which contributes to 7% of the state's electricity generation. Although only a fraction of the population and economy of the Pacific region, Nevada has significant opportunities for reducing greenhouse gas emissions through the deployment of CHP in their buildings sector, particularly in the growing hospitality industry.

The great majority – 93% – of Nevada's electricity needs are currently served by two major investor owned utilities (IOUs): Nevada Power Company and Sierra Pacific Power Company (NSOE, 2005). These two companies merged in 1999 and now are jointly held by Sierra Pacific Resources. The primary fuel used by both IOUs is coal. In addition, the publicly owned Colorado River Commission of Nevada and numerous cooperatives provide power for the rest of the state, predominantly in the rural areas. The two IOUs are not interconnected and evaluations of their load demands are treated independently of one another.

Electricity demands are growing rapidly in Nevada. The two major IOUs currently have a peak system demand of about 8.2 GW. This is forecast to grow to 10.3 GW by 2016 and to 12.2 GW by 2026 (NSOE, 2007). The Nevada utilities plan to meet these growing needs for electricity through a mix of new conventional generation, new renewables, and energy efficiency/demand side management programs.

Natural gas is supplied in Nevada by Southwest Gas Corporation and Sierra Pacific Power Company. Natural gas demands are also growing in Nevada, primarily for electricity generation in recent years but also for end-use applications. Nevada does not produce natural gas within the state and must therefore import it from other nearby states (NSOE, 2007).

A major issue for Nevada is the controversial construction plans for future coal-fired power generation in the state, relative to other power-generation alternatives. A specific recent issue is the potential construction of the Ely Energy Center (EEC). Since proposed, the EEC has proven to be highly controversial and the project has recently been delayed over environmental concerns. This plant has been proposed to provide 1500 MW of generation capacity and potentially up to 2500 MW, with the first of two 750 MW units to be online by 2015 and the potential for two additional 500 MW units to be added in a future phase (Sierra Pacific Resources, 2008). Figure 3, below, shows the location of the proposed EEC and a new transmission line that would connect the facility to Las Vegas.

Figure 3: Proposed Ely Energy Center
(Source: Sierra Pacific Resources, 2008)

Key organizations for the Pacific region CHP market include equipment suppliers and vendors, engineering and design firms, energy service companies, electric and gas utility companies (both “investor owned” and “municipal”), research organizations, government agencies, and other non-governmental organizations. Appendix D of this report includes a database of contact information for key organizations involved in the CHP market. The organizations listed in the appendix are those that have responded to requests for contact information. As subsequent revisions of this report are made, the PRAC expects the contact database to become more complete and comprehensive.

4. Overview of CHP Installations in Nevada

The Pacific region of California, Hawaii, and Nevada has several hundred 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. (EEA) database of CHP installations in the state shows a total of 947 sites. This total is not exactly correct because some of the older installations in the database may not be currently operational, and because the database is not comprehensive with regard to new installations. PRAC is working with EEA to update the database and improve its accuracy.

Table 1 shows a breakdown of the CHP sites by Pacific region state, along with additional data for the overall electricity generation in each state. California currently has approximately 9 GW of CHP capacity, with over 500 MW in Hawaii and 300 MW in Nevada. The average capacity of Pacific region CHP installations is 10.7 MW, and 55% of the CHP capacity is in large industrial systems of 50 MW or greater (Hedman, 2006). CHP systems in the western states of California, Hawaii, Nevada, and Arizona are estimated to be saving more than 370 trillion BTUs of fuel and 50 billion tons of CO_2 emissions per year, compared with the conventional generation they have replaced (Hedman, 2006).

Table 1: Electricity Generating Capacity and CHP Installations in the Pacific Region

	California	Hawaii	Nevada
Retail Customers (1000s)	13,623	435	981
Generating Capacity (MW)	56,663	2,267	6,856
Generation (Million MWh)	184	12	32
Retail Sales (Million MWh)	235	10	29
Active CHP (MW)	9,121	544	321
CHP Share of Total Capacity	16.1%	24.0%	4.7%

Source: Hedman, 2006

Nevada has fewer than ten CHP installations, most of which are in the industrial sector with units that are between 50 and 100 MW and powered by natural gas (Appendix A). Only one major casino employs co-generation, with a capacity of 5 MW. There is significant additional CHP potential in Nevada, particularly in the lodging and gaming industries.

5. Technical and Economic Status of Key CHP Technologies

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 2 below presents key characteristics of each of these types of generators.

Table 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 85% (AE)	Up to 75% (AE)	Up to 75% (AE)	Up to 75% (AE)	Up to 90% (AE)
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 (GTI)	$0.007-0.015/kWh (GTI)	$0.005-0.01/kWh
Maintenance Interval	5,000-8,000 hrs	ID	40,000 hours	ID	ID

Source: Data from Energy Commission, 2007, except Gas Tech. Institute for O&M costs as noted by "GTI" and "AE" for author estimates
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.
For more details on characteristics of specific fuel cell technologies, see: http://www.energy.ca.gov/distgen/equipment/fuel_cells/fuel_cells.html.

Additional CHP system equipment includes electrical controls, switchgear, heat recovery systems, and piping for integration with building HVAC systems. Waste heat can be used to assist boilers to raise steam for building heating systems, to directly provide space heating or heat (or steam) for industrial processes, and/or to drive absorption or adsorption chillers to provide cooling.

6. Summary and Status of CHP Policy Issues in Nevada

Important policy issues for CHP include utility interconnection procedures, utility rate structures including "standby charges" and "exit fees," and economic incentive measures. An overview of these CHP/DG policy areas for the Nevada market is provided below.

Grid Access and Interconnection Rules

On December 17, 2003, the Public Utilities Commission of Nevada (PUCN) adopted interconnection rules – known as Rule 15 -- for customers of Nevada Power and Sierra Pacific Power. The provisions of Rule 15 are consistent with California's interconnection standards (Rule 21), IEEE 1547 rules, and the model interconnection agreement of the National Association of Regulatory Utility Commissioners (NARUC). Rule 15 specifies interconnection procedures for the DG systems of up to 20 MW in size. Somewhat controversially, Rule 15 allows utilities to charge customer-generators for past fuel and purchased-power expenses in their tariffs (DSIRE, 2007).

The December 2003 agreement also revised Nevada's net metering standards for renewable energy systems including biomass-powered ones. The rules revised the net-metering program to allow systems of up to 150 kW to be net metered, up from a previous limitation of 10 kW (DSIRE, 2007a).

Market Incentives for CHP System Installation

Many states have already moved forward with incentivizing the deployment of CHP systems as a strategy for lowering energy and fuel costs as well as improving the overall reliability of power. Some utility companies also recognize the market value of CHP for both the avoided expansion of the grid and for end-users. Nevertheless, significant barriers to CHP are still present to lesser or greater degrees in each area. These include initial capital costs for projects, lack of utility interest, perceptions of safety issues, and unfamiliarity with CHP technologies.

In contrast to states like California, which have been actively promoting the installation of CHP systems through incentive programs, Nevada does not yet have clear plans for promoting CHP technology. Nevertheless, the state has taken steps toward working with industry and recognizes the need to change interconnection rules so that distributed generation can be better accommodated (NSOE, 2005; ACEEE, 2006). Nevada does not currently offer funding or rate class exemptions for CHP. However, they have established environmental regulations and net metering standards, which now encourage the implementation of a wide range of distributed power sources, and could potentially include CHP in the future.

Energy Portfolio Standard

As part of its restructuring efforts, Nevada established its Energy Portfolio Standard (EPS) in 1997. The PUCN administers the EPS and requires the two IOUs to obtain a certain fraction of their energy from renewable sources. The EPS was later revised in 2001 to require a scheduled portfolio increase of 2% every two years, hitting a maximum of 15% in 2013. In 2005, the EPS was amended once again under *Assembly Bill 3* (*AB 3*). Increases were raised to 3% every two years, reaching a maximum of 20% in 2015. The bill allows for the EPS to be met through renewable energy generation or credits and savings from efficiency measures. Also, *AB 3* requires that at least 5% of total electricity come from solar systems.

Under the current standard, systems that quality for the portfolio include biomass, solar, geothermal energy, wind, and some hydro projects. In addition, the PUCN has created a program that allows energy suppliers to buy and sell renewable energy credits (RECs) to help meet the standard and has also established a Temporary Renewable Energy Development (TRED) Program that assures renewable energy providers of their payments, encouraging them to expand their capacities.

Net Metering Rules and Utility Rates

First introduced in 1997, net metering in Nevada allowed IOUs to meter renewable systems up to 30 kW. The rules were subsequent modified in 2001, 2003, and 2005 to allow to systems as large as 150 kW. Nevertheless, for units greater than 30 kW, customers are required to install their own meter. Moreover, the utilities can arbitrarily charge interconnection facility and demand fees. For units smaller than 30 kW, net excess generation (NEG) could be carried over to the next billing cycle indefinitely. Under utility terms for time-of-use rates, the excess generation would be added to the same time-of-use period of the subsequent months (DSIRE, 2007a).

Nevada Power Company has a “Cogeneration and Small Power Production Qualifying Facility” program, which currently allows generators to participate in short term wholesale power markets and for large generators of 250 MW or more of capacity to enter into long term contracts. The short-term contract rate is set by a Dow Jones index and the log term rate is currently $0.041 per kWh (see Appendix B for details).

Governor’s Energy Plan

The state of Nevada has provided relatively little policy or financial support for DG and CHP. However, the Governor’s most recent comprehensive energy plan makes the following recommendations in its Chapter 6 (NSOE, 2005):

- “support a cautious approach to increased distributed generation, including utility-owned distributed generators”;
- “support a balanced portfolio of resource types, including base load, intermittent, peak load, rapid response generators for support of intermittent renewable generators”;
- make “incremental changes in tariffs to allow net metering and self-generation”; and
- make “changes in tariffs and interconnection rules to accommodate distributed generation.”

This language suggests a desire by the Governor’s office to further develop the DG market in Nevada. In future revisions of the energy plan, these general recommendations could be made more specific. The state legislature and/or the PUCN could also take more specific action, based on this general policy guidance by the Governor.

Energy Requirements for Government Buildings

Starting on July 1, 2007, Nevada will require that all public buildings sponsored or financed by the state must meet standards specified by the Leadership in Energy and Environmental Design (LEED) system (NRS 338.187). Technologies that earn LEED certification points include passive solar space heating, and renewable energy systems (including biomass and biogas), as well as a potential point or two for CHP systems more generally in the “innovation and design” category. In addition, the measure requires at least two constructed public buildings to meet the equivalent of LEED “silver” or higher over every two-year period.

7. The Market Potential of CHP Systems in Nevada

Nevada has significant CHP opportunities in both existing and newly built facilities, and has exploited the potential for CHP to contribute to state generating capacity less than other states in the region. As discussed below, a recent Nevada CHP technical market potential assessment report found that over 2 GW of CHP additions were possible (EEA, 2005a). Not all of this technical CHP resource is fully economic to develop (i.e., with rates of return and simple payback times acceptable to the private sector), particularly absent a state-level incentive program, as discussed in a later section. However, based on economic CHP potential assessments done in California and other states, the economic potential in Nevada through 2020 is likely to be well over 200 MW, and probably more likely in the 300-500 MW range.

One of the most high value CHP opportunities in Nevada is in the major lodging, resort, and casino sector. The size and character of this sector in Nevada provides it with a significant opportunity to implement CHP in larger, higher-end hotels. The EPA estimates that about 10,000 hotels nationwide have energy demand profiles that can be efficiently met by CHP, and Nevada establishments have the highest average number of rooms in the country. Many existing sites in Nevada are eligible for conversion to CHP, and many more lodging units are expected to be built with the tourism and gambling industries expanding for the foreseeable future.

With regard to the hotel potential specifically, the EPA estimates that about 10,000 hotels nationwide have energy demand profiles that can be efficiently met by CHP. Up to this point, only a relatively small number of hotels have installed CHP, with California having the greatest number of installations at 95 hotels, followed by New Jersey, and New York (EEA, 2005b). Most of the existing installations are reciprocating engines that were installed in the 1980s. As CHP technologies have evolved over the past 20 years, potential system types now also include microturbines, fuel cells, and gas turbines.

The major lodging, resort, and casino sector provides Nevada with a significant opportunity to implement CHP in higher-end hotels. These establishments have the highest average number of rooms in the country. Table 3, below, shows that on average, Nevada has the largest hotels in the U.S. with over 1,200 rooms per hotel.

Table 3: Summary of Hotel Capacity in States in the U.S.

Most Luxury and Upper Upscale Hotels	Hotels	Largest Average Upper Upscale Hotels	Avg. Rooms / Hotel
California	246	Nevada	1,214
Florida	162	Hawaii	728
Texas	124	New York	515
New York	73	Louisiana	515
Illinois	73	District of Columbia	510
Georgia	56	Illinois	449
Virginia	55	Georgia	423
Arizona	49	California	406
Massachusetts	46	Alaska	404
Colorado	45	Massachusetts	390
Percent of U.S.	58.1%	Average Rest of U.S.	338

Source: EEA, 2005b

Previous installations suggest that custom-designed CHP systems can economically meet up to 75% of the total energy needs of these sites, which typically consist of space heating and cooling, water heating, lighting, and restaurant and laundry operations. To be practical, CHP systems for hotels typically require facilities of at least 100 rooms in size. For a 100 to 200-room site, an appropriate CHP system might consist of a 100-kW reciprocating engine or microturbine system that supplies electricity and waste heat for domestic hot water, space heating, and laundry needs. For larger hotels and especially for casino hotels, it is likely to make technical and economic sense to also include absorption chillers for chilled water and/or air conditioning.

Appendix B includes a list of major casinos and hotels in Nevada, with 115 entries. These hotels/casinos have a combined total of over 116,000 rooms. This list indicates that Nevada has about 40 hotel/casinos of over 1,000 rooms, representing a major opportunity for CHP at these facilities to provide more efficient onsite generation, cost savings for the facility, reduced pollutant emissions, and reduced reliance on the electrical grid.

With a general rule that hotels with over 100 rooms may find CHP economical, we can get a rough sense of the economic potential in this sector by applying the example case study shown below, for the Rio All-Suites Hotel and Casino in Las Vegas that recently installed a 4.9 MW CHP system. If the other hotels listed in Appendix B with over 100 rooms each installed a CHP system scaled relative to the one installed at the Rio All-Suites (which has 2,500 rooms), that would equal about 230 MW of CHP capacity in this sector alone.

Nevada CHP Case Study – Rio All-Suites Hotel and Casino

As an example of the potential for CHP in the Nevada hotel and casino sector, consider the system installed by the Rio All-Suites Hotel and Casino in Las Vegas. This first casino CHP system in Nevada went online in May of 2004 and is providing about 50% of the facility's annual electricity requirements and much of its water and space heating. The hotel has 2,500 rooms and 16 restaurants.

The system consists of six reciprocating engine generators by Caterpillar (each rated at 817 kW for a total of 4.9 MW), with the waste heat used for water and space heating. The system cost about $7.5M to install and with estimated energy cost savings of $1.5M per year, it is expected to provide a simple payback of about 5 years. The overall thermal efficiency of the system is projected to be about 75%, once the captured waste heat is factored in.

Along with additional backup generators, the CHP systems can continue to provide power in the event of a blackout by supplying electricity and hot water for the facility's most important requirements.

Pictured: Caterpillar reciprocating engine generator and hot water loop

CHP System Quick Facts

4.9 MW Reciprocating Engine CHP System

Initial cost:
$7,500,000
Expected net annual savings:
$1,500,000/yr
Simple Payback:
5 years
Overall Efficiency:
~75% (overall thermal)

Note: See http://www.chpcenterpr.org for more details of this project and other CHP case studies from the Pacific region

EEA has recently completed a market assessment report for Nevada and Arizona that indicates that Nevada has a technical potential for 2,334 MW of additional CHP through 2020. EEA estimates that 1,792 MW of this potential is in existing facilities, and 1,216 MW of the potential is in new facilities that were expected to be built between 2005 and 2020.

As of 2008, with development since 2005, the opportunity for retrofitting CHP into existing facilities should be somewhat greater, perhaps about 2,075 GW (with an average of 5% annual growth over that time). Meanwhile, the potential in new facilities would be slightly less at this point, when assessed through the year 2020.

Note that the total technical potential is reduced somewhat to arrive at the 2,334 MW figure to avoid double counting in some applications where both traditional and cooling CHP opportunities were assessed. Table 4 below presents these technical potential estimates by existing and new facilities and the application (EEA, 2005a).

Table 4: Estimate of Nevada CHP Technical Market Potential by Application

CHP Type	**MW Capacity**
Existing Facilities (MW)	
Industrial – On Site	316
Commercial - Traditional	669
Cooling CHP	801
Large Industrial – Export	0
Resource Recovery	6
New Facilities (2005-2020) (MW)	
Industrial – On Site	32
Commercial/Institutional	518
Cooling CHP	666
Net Total Technical Potential*	**2,334**

Source: EEA, 2005a
Note: *Total adjusted to avoid double counting some applications that are analyzed in both traditional and cooling CHP categories

Nevada's technical CHP potential through 2020 is thus estimated to be over 2.3 GW, with the majority of that, and perhaps as much as 2 GW, being in the form of retrofit opportunities in existing facilities that could be developed right away. The projections for opportunities in new facilities are probably conservative given Nevada's likely growth rate over the next ten to fifteen years and the many possible commercial and industrial applications where CHP can be applied.

With regard to the potential for CHP that could be economically developed – i.e., with "reasonable" payback times of 4-5 year or less – a detailed assessment of Nevada has not yet been performed, but detailed estimates of economic CHP potential have been made for the California market. One recent assessment found that about 1.1 GW to 7.3 GW of new CHP can be economic in California, depending on market conditions and the presence of support policies (EPRI, 2005). This compares to a technical potential that is believed to be as high as about 30 GW when both retrofit opportunities and new construction through 2020 are considered (EPRI, 2005).

Figure 4, below shows that most potential CHP system adopters require a payback time of less than 5 years, but that those who are already seriously considering CHP systems (the "strong prospects") are more likely to accept somewhat longer payback times. Municipal entities often can accept longer paybacks of 10 or more years, and some private sector entities may accept longer payback times as well if there are significant "green public relations" benefits (e.g., the high temperature fuel cell and solar PV systems at the Sierra Nevada Brewing Company in Chico, California).[3]

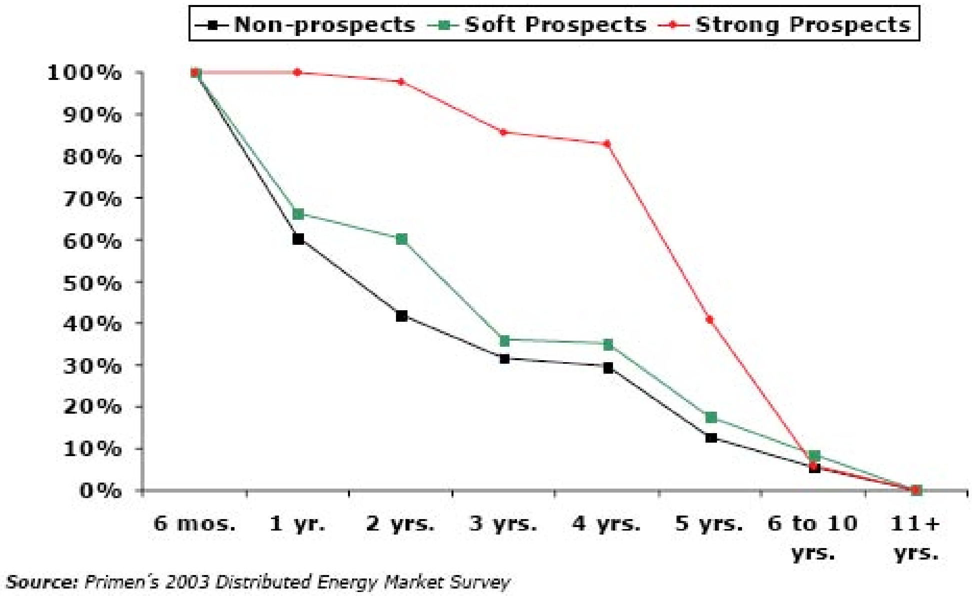


Figure 4: Acceptable CHP/DG System Payback Time by Percentage of Respondents

Nevada's "spark spread" (the difference between the prevailing price of electricity and the cost of the input fuel for power production) is slightly smaller than California's. However, recent data suggest that commercial customers in Nevada are only paying about $0.01/kWh less than in California (10.46 ¢/kWh in Nevada vs. 11.48 ¢/kWh in California). Meanwhile, industrial customers in Nevada on average pay about 1.5 ¢/kWh less than in California (7.80 ¢/kWh in Nevada vs. 9.45 ¢/kWh in California) (U.S. EIA, 2008).

In comparison to these utility rates, medium to large-sized CHP systems (in the range of 500 kW to 50 MW) can have levelized electricity costs of around $0.055-0.065/kWh (WADE, 2006). A general "rule of thumb" is thus that if commercial or industrial customers are paying more than about $0.07/kWh and have fairly large and steady thermal loads (either heating, cooling, or both), they may be attractive candidates for a CHP project.

Give all of this, a reasonable estimate for economic CHP market potential in Nevada through 2020 would appear to be at least 200 MW, and very likely more in the 300 to 500 MW range. Furthermore, much of this opportunity exists in the retrofit market and could be pursued very rapidly. The potential in Nevada is likely to be at least as high as California's in a relative sense because CHP has been less fully developed in Nevada and many of the more attractive opportunities are likely to remain. This suggests that estimates on the higher end of the 300 to

[3] Visit http://www.chpcenterpr.org for this and other CHP case studies in the Pacific region

500 MW range through 2020 are not implausible, are potentially readily achievable, and even could potentially be exceeded if supportive state policies are adopted.

It is important to note that because CHP makes more efficient use of natural gas, and also can run on biogas where this is a natural methane source (e.g., dairy farm, landfill, wastewater treatment plant, etc.), significant carbon emission reductions are possible. For example, as shown in Figure 5, the Electric Power Research Institute (EPRI) calculates that a 300 kW CHP system could provide an annual reduction of 778 tons of carbon dioxide, relative to natural gas fired central generation. A 5 MW CHP system for a major hotel/casino could potentially have emission reductions of about 13,000 tons per year, or almost 400,000 tons over a 30-year project life.

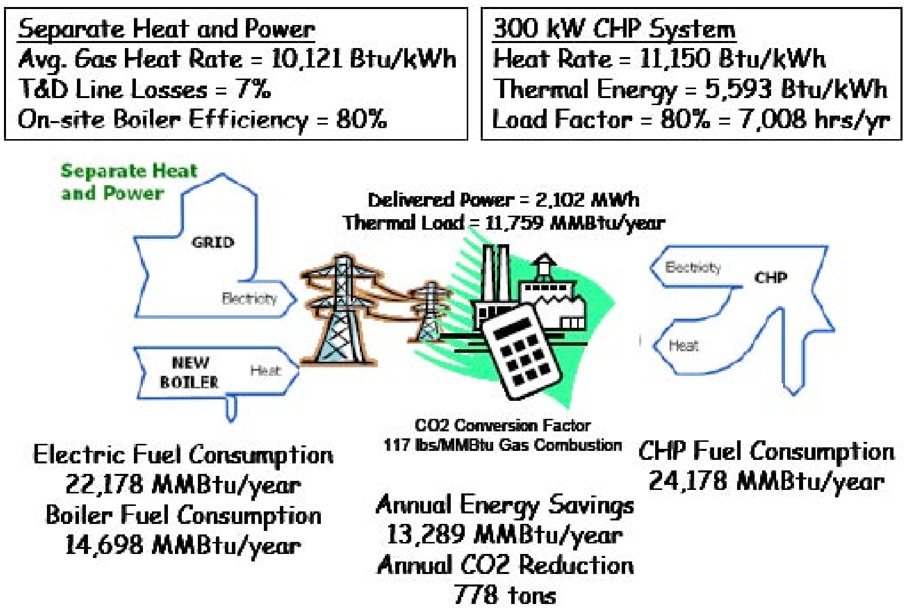


Figure 5: Estimate of the Carbon Reduction Benefits from CHP Systems (Source: EPRI, 2005)

With an average car producing about 2 tons of carbon dioxide per year, even the relatively modestly sized, 300-kW system would provide similar benefits to taking 390 cars off of the road. If Nevada could succeed in doubling its installed base of CHP by 2020 (with an additional 320 MW of CHP generation), that would provide the equivalent carbon dioxide emission reduction benefit of taking 415,000 vehicles off of Nevada's roads, even if the alternative power source were natural gas.

With the prospect of additional coal-fired generation to meet Nevada's needs, instead of natural gas, the benefits of installing CHP as an alternative would be even greater. In the above example, instead of 415,000 vehicles, the impact of doubling Nevada's installed CHP base would be closer to the effect of taking 700,000 vehicles off the road. And when CHP is powered with biogas at dairy manure digesters and wastewater treatment plants, the greenhouse gas benefits are tremendous. This is because the bio-methane that otherwise would be emitted (with a climate impact more than 30x that of carbon dioxide, per molecule) is converted to carbon dioxide during the course of the CHP system operation, a much preferable outcome.

8. Summary of CHP System Financial Assistance Programs

There are no specific state incentive programs for CHP system installation in Nevada. The state's net metering program provides a form of incentive for biomass-based CHP projects, of 150 kW or less, by allowing export of extra power to the grid that can then be withdrawn at a later time. The main applicable financial assistance programs include federal tax programs and CHP project screening services that are available on a limited basis from the PRAC and the U.S. Environmental Protection Agency.

Federal investment tax credits for CHP system installation have been included under various energy policy legislation proposals in recent years. At present, investment tax credits are available for fuel cell and microturbine installations, but not for CHP systems more generally. A broader CHP federal investment tax credit of 10% was proposed under the 2005 Energy Policy Act, but was cut in the final conference meeting at least partly due to a shift in Office of Management and Budget methodology that showed the program to be a net resource consumer instead of a revenue generator. The USCHPA is currently working on a new proposal for a federal CHP investment tax credit, with either a 20 MW or 50 MW cap on qualifying system size.

For energy end-users in Nevada that are interested in potential CHP projects, both the PRAC and the U.S. EPA offer services to perform initial project screenings to determine CHP system feasibility, optimal system type and size, and potential system economics. The PRAC feasibility studies are conducted by San Diego State University, with a team of experts deployed to the site to collect equipment and energy use data and a year of utility bills. The CogenPro software package is then used to determine optimal system sizing and approximate system economics. Project screenings are offered by the PRAC on either a no-charge or cost-shared basis, depending on the nature of the potential installation.[4]

The U.S. EPA also offers initial CHP project screening services. Interested parties can contact EPA staff, and if qualified, can then fill out a data submittal form that is available on the U.S. EPA CHP Partnership website. They will then receive a report with the findings from the "Level 1" screening analysis.[5]

9. Action Plan for Advancing the CHP Market in Nevada

Nevada has some of the basic elements in place for expansion of the CHP market, but lags behind other states in certain key respects. Nevada has an interconnection standard but no financial incentives for CHP system installation. The state has lower energy prices than other states in the Pacific region, limiting the future market potential of CHP systems to particularly attractive locations.

We recommend consideration of the following measures for advancing the CHP market in Nevada:

1. Consider legislation to provide capital cost buy-down incentives and/or low-interest loan programs for CHP systems, potentially with a performance-based component

Nevada currently has a modest system benefits charge on electricity sales to promote demand-side management programs. This incentive could be extended – or other public funds could be

[4] For more details on PRAC CHP project feasibility screenings, please visit http://www.chpcenterpr.org or contact Dr. Asfaw Beyene directly at abeyene@rohan.sdsu.edu.
[5] For more details, please visit: http://www.epa.gov/chp/project_resources/tech_assist.htm

appropriated – to provide capital cost buy-down incentives for CHP systems in order to encourage installations where they can provide enhanced energy efficiency. The incentives could be scaled relative to the efficiency and environmental benefits of various system types, as in the California Self-Generation Incentive Program. Or, the incentives could be tied the projected energy efficiency of the installation or the actual performance of the system over time, where the incentive could be paid out over the first years of the project rather than entirely as an up-front payment. Alternatively or in addition, low-interest loan programs could be considered to help small and medium sized businesses to raise the capital needed to install CHP systems at their sites

2. Institute co-metering for CHP systems to allow for power export to the grid with rules for power purchase from CHP system owners based on wholesale power prices plus consideration for their T&D, grid support, and GHG reduction benefits

In some cases, CHP system sizes are limited by rules that restrict their ability to export power to utility grids, rather than by the thermal loads at the site. Allowing export of power from CHP systems to utility grids under a wholesale power market would entail administrative complexities for utilities, but we believe that in many cases these would be offset by the benefits that could be obtained. Export of power from CHP systems to utility grids could be accomplished through co-metering, whereby one utility meter measures power usage and a second meter measures power exports. Net exports of power could then be compensated at wholesale power rates, thus incentivizing CHP system operation at times of high electricity prices and peak system demand. These payments could potentially be augmented by consideration of T&D and grid support benefits, and environmental benefits in terms of reduced GHG emissions compared with those from conventional generation. In Nevada, this would represent an extension of the current net-metering program, which currently allows for net-metering of biomass-based projects but not the actual sale of power to wholesale markets from customer generators.

3. Encourage the use of CHP as a power reliability measure for critical need applications such as refineries, water pumping stations, emergency response data centers, etc.

CHP systems offer the potential for energy supply (both electrical and thermal) with reduced costs and environmental impacts compared with conventional systems. In settings that also require high-reliability power and that are currently backup up with rarely-used generator systems, CHP systems can provide the additional functionality of providing backup power with the incorporation of fuel storage to protect against fuel supply disruptions. The economics of CHP in these settings can be further enhanced through this combined functionality, whereby existing backup generators can be decommissioned and replaced with CHP systems that can provide day-to-day power along with emergency “black start” power services. The PRAC will be studying these applications in greater detail in 2007, in the context of specific premium power settings in the Pacific region.

4. Include DG/CHP in the state integrated resource planning process

Investments in DG/CHP systems should be considered along with other power generation system investments in the context of Nevada’s integrated resource planning (IRP) process. Specific attention should be paid to the economic and environmental benefits that CHP systems can provide relative to the “status quo” option of building additional coal-fired generation to meet the state’s growing energy needs. Additional benefits to consider include grid-support for local utility systems as well as backup power/power quality for sites that adopt CHP.

5. Consider PUCN direction to the Nevada utilities to develop more consistent and favorable utility tariff structures for CHP customers

Utility rates are often structured in ways that disadvantage customer-owned generation systems. CHP system owners are disadvantaged when short periods of system downtime in a given month negate their savings of facility-related demand charges. It is in general reasonable for utility operators to insist that CHP facilities be reliable and available, but a system downtime of e.g. 15 minutes per month is enough to eliminate demand charge savings in many cases, and this translates into an availability of over 99.9%. Meanwhile, independent power producers subject to power purchase agreements are typically expected to achieve system availabilities of 90-95%. We recommend that the PUCN establish regulations such that demand charges are assessed over 1 or 2-hour blocks, rather than 15 or 30 minutes, so that brief periods of system downtime do not negatively impact CHP system economics in an unreasonable fashion.

10. Conclusions

Nevada is the highest growth state in the country in terms of population and energy demand growth. The state has relatively little CHP installed at present, with only a few hundred MW of installed capacity. The hotel and casino sector represents a particularly attractive sector for CHP systems, and one that is growing rapidly. Additional market potential includes the hospital, grocery, and wastewater treatment sectors, and some remaining mining and industrial sector opportunities.

There are only about 300 MW of CHP in Nevada at present, or less than 5% of state capacity, compared with nearby states that have much higher levels of CHP market penetration (e.g., about 9 GW or about 16% of capacity in California). Nevada's technical CHP potential is estimated at well over 2 GW. A detailed assessment of the economic potential for CHP in Nevada has yet to be conducted, but assessments for California suggest that the economic potential in Nevada is likely in the 300-500 MW range through 2020, with most of the opportunity in retrofit applications that could be pursued immediately. Supportive state policies could be critical to achieving the high end of that range, or potentially even exceeding it. The Nevada hotel/casino sector alone appears to have over 200 MW of economic potential for retrofit systems, with more in the future in new construction.

Further DG/CHP policy development in Nevada could be important to furthering CHP opportunities in the state. Some basic elements are in place, in terms of interconnection standards for systems of up to 20 MW in size and net-metering programs for renewable systems. Additional programs to provide financial support for CHP system installation – to encourage them for their energy efficiency, economic, and environmental benefits – and to consider further development of CHP compared with other alternatives in the context of the state IRP process, would be helpful to further develop the CHP market in Nevada.

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Appendix A – Operational CHP Systems in Nevada

City	Facility Name	Application	Op Year	Capacity (kW)
Carson City	Carson City Aquatic Center	Amusement/Recreation	2002	150
Fernley	Quebecor Printing Nevada Inc.	Printing/Publishing	2000	3,000
Gardnerville	WJN Enterprises	Nursing Homes	-	15
Henderson	Pioneer Alkali Company	Chemicals	1991	90,000
Las Vegas	Spring Gardens Greenhouse/Sunco	Agriculture	1994	53,000
Las Vegas	Georgia Pacific Garnet Valley Project	Pulp and Paper	1992	85,000
Las Vegas	Pabco Gypsum Black Mountain Project	Stone/Clay/Glass	1993	85,000
Las Vegas	Rio All-Suite Hotel and Casino	Hotels	2003	4,900

Source: EEA, 2005

Appendix B – Cogeneration and Small Power Production Qualifying Facilities Schedule

NEVADA POWER COMPANY
P.O. Box 98910
Las Vegas, NV 89151
Tariff No. 1-B
cancels
Tariff No. 1-A (withdrawn)

35th Revised	PUCN Sheet No. **32**
Cancelling **34th Revised**	PUCN Sheet No. **32**

COGENERATION AND SMALL POWER PRODUCTION - QUALIFYING FACILITIES
SCHEDULE QF – SHORT TERM

APPLICABLE – This schedule is applicable only to short term purchases from qualifying facilities as set forth in NAC 704.8711 through NAC 704.8793.

AVAILABLE – To qualifying facilities located in the Company's service area.

RATES
Utility will pay the sum of the following rates for the energy and capacity provided as determined by meter readings:

(1) ENERGY RATE

ALL MONTHS:

FIRM ENERGY

The rate paid for firm on-peak or firm off-peak energy deliveries shall be calculated for each hour as follows:
The hourly rate paid shall equal the applicable firm on-peak or firm off-peak price taken from the daily Dow Jones Mead/Marketplace Electricity Price Index shaped by the Dow Jones Palo Verde hourly index report for the same day.

NON-FIRM ENERGY

The rate paid for non-firm energy deliveries shall be calculated for each hour and is defined as the lesser of:

The highest hourly system incremental generation cost. The incremental generation cost shall be calculated based on the daily incremental fuel cost and the applicable unit's incremental heat rate curve; or
The hourly Market Price calculated from the applicable firm on-peak or firm off-peak price taken from the daily Dow Jones Mead/Marketplace Electricity Price Index shaped by the Dow Jones Palo Verde hourly index report for the same day.

(2) CAPACITY RATE – The capacity cost is included in the above firm energy rate.

(Continued)

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COGENERATION AND SMALL POWER PRODUCTION - QUALIFYING FACILITIES
SCHEDULE QF – SHORT TERM
(Continued)

SPECIAL CONDITIONS

1. Subject to the provisions of 18 C.F.R. § 292.304 (f), the Utility will accept all offered purchases.

2. Qualifying Facilities providing energy to Utility hereunder shall be entitled to receive electric service from Utility on the filed rates schedule(s) contained in Utility's Electric Tariff No. 1-B applicable to the type and location of the Qualifying Facility.

3. Should the index described under ENERGY RATE section become permanently unavailable, the Utility shall refile its tariff as soon as reasonably possible. Until the refiled tariff becomes effective, Qualifying Facilities shall be paid a rate per MWH equal to the average of the applicable firm on-peak or firm off-peak daily Mead/Marketplace Index prices for the last available month.

4. The Dow Jones Mead/Marketplace Electricity Price Index firm on-peak and firm off-peak prices are not published on Sundays and NERC holidays. The price paid for any energy and capacity delivered on Sunday or NERC holidays shall be based on the "Sunday and NERC Holiday 24 Hour" Mead/Marketplace Index price shaped by the Dow Jones Palo Verde hourly index report for the same day. If the "Sunday and NERC Holiday 24 Hour" Mead/Marketplace Index price is not available, the price paid for any energy and capacity delivered on Sunday or NERC holidays shall be the firm on-peak and firm off-peak price from the last available day.

5. If the Dow Jones Palo Verde hourly index report referenced in the ENERGY RATE section of this tariff and special condition 4 is not published for the same day, then the last published index report shall be used to shape the firm on-peak and firm off-peak daily Mead/Marketplace Index prices.

6. The Utility shall provide upon demand to any person who receives or desires to receive payment under this schedule, all materials and procedures used in calculating rates for this schedule.

7. Firm energy is defined as (1) Energy that has firm resources backing up the energy and is under a firm contract for delivery to the utility, or (2) energy that has been pre-scheduled, or (3) energy that is financially firm and backed up with liquidated damages pursuant to the terms of a contract between the Utility and the Qualifying Facility governing liquidated damages. Energy not meeting the criteria of firm energy will be considered and paid at the non-firm rate.

COGENERATION AND SMALL POWER PRODUCTION - QUALIFYING FACILITIES
SCHEDULE QF – LONG TERM

AVAILABLE: To qualifying facilities willing to execute thirty (30) year contracts, until the Company executes and the Commission approves contracts, for at least two hundred fifty (250) megawatts of capacity, other than the capacity associated with contracts approved by the Commission prior to January 1, 1990, from qualifying facilities or until the Commission approves an amended or new resource plan for the Company, whichever comes first.

APPLICABLE: To the purchase of electrical energy and capacity from qualifying facilities as defined in NAC 704.8771 through NAC 704.8793

TOTAL RATE:

All Hours	$0.04100 per kWh

SPECIAL CONDITIONS

TIME DIFFERENTIATION: The Company and the qualifying facilities shall time differentiate the above cited rate prior to incorporation of such rate into power purchase contracts. Such time differentiated rates shall be filed with the Commission for review and approval.

ANNUAL ADJUSTMENT: The rate under this schedule shall be effective through April 30, 1991. The rate under this schedule shall be adjusted annually on May 1 of each year to reflect changes in the Consumer Price Index for All Urban Consumers experienced during the preceding year. The base index for the first adjustment shall be the index for January 1, 1990.

CONTRACT REQUIREMENT: Purchases of capacity and/or energy from qualifying facilities shall not be undertaken by the Company prior to the execution of a power purchase contract generally in the form on file with the Commission.

SUPPLEMENTAL AND STANDBY SERVICE: Supplemental and Standby Service shall be provided in accordance with the Company's retail tariff on file with the Commission.

OPERATING COST ADJUSTMENT: The Company reserves the right to adjust the rates under this schedule to reflect changed operating costs attributable to purchases of capacity and/or energy from qualifying facilities. Such adjustments shall be subject to Commission Approval.

NEVADA POWER COMPANY
P.O. Box 230
Las Vegas, NV 89151
Tariff No. 1-B
cancels
Tariff No. 1-A (withdrawn)

Second Revised PUCN Sheet No. **33**
Cancelling **First Revised** PUCN Sheet No. **33**

COGENERATION AND SMALL POWER PRODUCTION - QUALIFYING FACILITIES
SCHEDULE QF
(Continued)

In order to qualify for a capacity payment, the following provisions must be met:

1. The Contract Capacity for payment purposes may not exceed the lowest capacity rating in any of the six peak months on Company's system, which are presently the months of May, June, July, August, September and October.

2. The Contract Capacity must be available[2] for all of the on-peak hours subject to an allowance of 10 percent of those on-peak hours for forced outages.

3. Scheduled outages must be performed in the months of March and April.

4. Contracts shall be required for all purchases hereunder. Such contracts will include the division of costs and responsibilities of both Company and Seller for metering, interconnection, control, protection and Special Facilities Charges. Where applicable, the contract shall state the available contract capacity.

GENERAL PROVISIONS

1. The billing and accounting period used herein shall be one (1) calendar month.

2. Payment for energy and capacity is due on or before thirty (30) days following the end of each billing month.

3. Charges for Supplementary Power will be in accordance with Company's applicable retail rate schedules filed with the Nevada Public Service Commission.

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[2] As used herein "available" means either dispatchable by Company or actually delivered to Company.

SPECIAL CONDITIONS – Refer to Rule 15 (C)

SYSTEM EMERGENCIES – Qualifying facilities are obligated to provide power during system emergencies as set forth in General Order No. 32 Section 7.0 System Emergencies. (C)

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Source: Nevada Power, 2004

Appendix C – Major Hotel/Casinos in Nevada as CHP Market Opportunities

City	Hotel/Casino Name	Rooms	Restaurants
Beatty	Exchange Club Casino Motel Restaurant & Bar	44	1
Boulder City	Hacienda Hotel & Casino	375	3
Carson City	Carson City Nugget Hotel Casino	80	5
Carson City	Carson Station Hotel Casino	92	1
Carson City	Casino Fandango	No	5
Carson City	Pinon Plaza Resort Casino	148	3
Crystal Bay	CalNeva Resort and Spa	220	1
Crystal Bay	Tahoe Biltmore Lodge and Casino	70	2
Henderson	Eldorado Casino	No	3
Henderson	Fiesta Henderson Casino Hotel	224	4
Henderson	Sunset Station Hotel Casino	400	9
Henderson	The Green Valley Ranch Station Casino	200	6
Incline Village	Hyatt Regency Lake Tahoe Resort and Casino	458	4
Jackpot	Cactus Petes Resort Casino	300	5
Jackpot	Four Jacks Hotel and Casino	60	1
Jackpot	Horseshu Hotel & Casino	120	6
Lake Tahoe	Caesars Tahoe Resort and Casino	440	4
Lake Tahoe	Lake Tahoe Horizon Hotel and Casino	539	3
Las Vegas	Arizona Charlie's Hotel & Casino – East	303	5
Las Vegas	Arizona Charlie's Hotel & Casino – West	258	5
Las Vegas	Bally's Hotel Casino	2,900	6
Las Vegas	Barbary Coast Hotel Casino	200	3
Las Vegas	Barcelona Hotel Casino	172	1
Las Vegas	Bellagio Hotel Casino	3,000	17
Las Vegas	Best Western Mardi Gras Inn and Casino	314	1
Las Vegas	Binion's Horseshoe Hotel & Casino	360	4
Las Vegas	Boardwalk Casino – Holiday Inn	654	5
Las Vegas	Boulder Station Hotel Casino	300	8
Las Vegas	Bourbon Street Hotel & Casino	166	1
Las Vegas	Caesar's Palace Hotel Casino	2,500	11
Las Vegas	California Hotel Casino	781	8
Las Vegas	Casino Royale & Hotel	152	3
Las Vegas	Circus Circus Hotel Casino	3,500	9
Las Vegas	Excalibur Hotel Casino	4,032	7
Las Vegas	Fiesta Rancho Casino Hotel	100	5
Las Vegas	Fitzgeralds Hotel Casino	638	5
Las Vegas	Flamingo Hotel Casino	3,600	8
Las Vegas	Four Queens Casino Hotel	690	7
Las Vegas	Fremont Hotel & Casino	447	5

Las Vegas	Gold Coast Hotel Casino	750	8
Las Vegas	Golden Nugget Hotel Casino	1,500	3
Las Vegas	Hard Rock Hotel and Casino	650	6
Las Vegas	Harrah's Hotel Casino	2,500	8
Las Vegas	Imperial Palace Hotel and Casino	2,700	10
Las Vegas	Lady Luck Casino Hotel	797	4
Las Vegas	Luxor Las Vegas Hotel Casino	4,000	9
Las Vegas	Mandalay Bay Resort and Casino	3,200	16
Las Vegas	MGM Grand Hotel Casino	5,034	15
Las Vegas	Mirage Hotel Casino	3,044	8
Las Vegas	Monte Carlo Hotel Casino	3,002	7
Las Vegas	Nevada Palace	210	3
Las Vegas	New York New York Hotel Casino	2,000	9
Las Vegas	Palace Station Hotel Casino	1,000	8
Las Vegas	Paris Las Vegas Hotel Casino	3,000	10
Las Vegas	Planet Hollywood Resort Casino a Sheraton Hotel	2,567	11
Las Vegas	Rampart Casino	541	3
Las Vegas	Rio All Suite Hotel & Casino	2,500	16
Las Vegas	Sahara Hotel and Casino	1,700	6
Las Vegas	Sam's Town Hotel Casino	648	5
Las Vegas	San Remo Hotel Casino	711	4
Las Vegas	Santa Fe Station Hotel and Casino	200	3
Las Vegas	Silverton Hotel Casino RV Park	300	2
Las Vegas	Stardust Hotel Casino	1,500	7
Las Vegas	Stratosphere Casino Hotel & Tower	2,444	14
Las Vegas	Suncoast Hotel & Casino	392	7
Las Vegas	The New Frontier Hotel & Casino	970	7
Las Vegas	The Orleans Hotel and Casino	800	8
Las Vegas	The Palms Casino Resort	450	8
Las Vegas	The Riviera Hotel and Casino	2,100	6
Las Vegas	The Venetian Hotel Casino	3,000	15
Las Vegas	Treasure Island Hotel Casino	2,800	9
Las Vegas	Tropicana Resort & Casino	1,900	7
Las Vegas	Tuscany Hotel Casino	712	2
Laughlin	Avi Resort & Casino	300	5
Laughlin	Colorado Belle Hotel Casino	1,200	6
Laughlin	Edgewater Hotel Casino	1,421	6
Laughlin	Flamingo Hotel Casino	1,900	6
Laughlin	Golden Nugget	300	5
Laughlin	Harrah's Hotel Casino	1,600	5
Laughlin	Pioneer Hotel & Gambling Hall	416	3
Laughlin	Ramada Express Hotel & Casino	1,501	7
Mesquite	Eureka Casino Hotel	210	1
Mesquite	The CasaBlanca Hotel Casino Golf and Spa	500	3
Mesquite	The Oasis Resort Casino Golf and Spa	1,000	5
Mesquite	The Virgin River Hotel/Casino/Bingo	724	3

Minden	Carson Valley Inn	230	3
North Las Vegas	Texas Station Gambling Hall & Casino	200	7
Primm	Buffalo Bill's Resort & Casino	1,242	4
Primm	Primm Valley Resort and Casino	624	4
Primm	Whiskey Pete's Hotel & Casino	777	3
Reno	Atlantis Hotel Casino	1,000	7
Reno	Bonanza Casino	No	2
Reno	Bordertown Casino. RV Resort	No	1
Reno	Circus Circus Hotel Casino	1,572	5
Reno	Club Cal Neva Casino	300	6
Reno	Eldorado Hotel Casino	817	10
Reno	Fitzgeralds Hotel Casino	351	3
Reno	Grand Sierra Resort and Casino	1,000	9
Reno	Harrah's Hotel Casino	975	3
Reno	Peppermill Hotel Casino	1,255	7
Reno	Sands Regency Hotel Casino	800	5
Reno	Siena Hotel Spa Casino	214	2
Reno	Silver Legacy Resort Casino	1,720	6
Sparks	Alamo Travel Center	70	1
Sparks	Baldini's Sports Casino	No	3
Sparks	John Ascuaga's Nugget Hotel Casino	1,600	9
Sparks	Silver Club and Casino	206	4
Sparks	Western Village Inn & Casino	280	4
Stateline	Bill's Casino	No	1
Stateline	Harveys	740	6
Stateline	Lakeside Inn and Casino	124	2
Verdi	Boomtown Hotel Casino	347	4
West Wendover	Montego Bay Casino and Resort	300	3
West Wendover	Peppermill Hotel and Casino	300	3
West Wendover	Rainbow Hotel and Casino	450	4
Winnemucca	Winners Hotel Casino	123	2

Source: http://www.statescasinos.com/travel/hotel/casinos/Nevada/nvCasinos.html

Appendix D – Contact Information for Key Pacific Region CHP Organizations

Note: To be added to this database, or to make any corrections, please send an email to Tim Lipman at telipman@berkeley.edu

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Assessment of Combined Heat and Power Premium Power Applications in California

Final Project Report

September 30, 2008

Prepared by:

Pacific Region CHP Application Center
U.S. Department of Energy Grant FED-03-015

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University of California - Berkeley
Energy and Resources Group

Acknowledgments

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We also thank the many other people who provided information and permissions needed for the project profiles to be developed. Of course, the authors alone are responsible for the contents herein.

Table of Contents

Executive Summary

This “Assessment of Combined Heat and Power Premium Power Applications in California analyzes the current economic and environmental performance of combined heat and power (CHP) systems in power interruption intolerant commercial facilities. Through a series of three case studies, key trade-offs are analyzed with regard to the provision of black-out ridethrough capability with the CHP systems and the resutling ability to avoid the need for at least some diesel backup generator capacity located at the case study sites.

Each of the selected sites currently have a CHP or combined heating, cooling, and power (CCHP) system in addition to diesel backup generators. In all cases the CHP/CCHP system have a small fraction of the electrical capacity of the diesel generators. Although none of the selected sites currently have the ability to run the CHP systems as emergency backup power, all could be retrofitted to provide this blackout ride-through capability, and new CHP systems can be installed with this capability.

The following three sites/systems were used for this analysis:

<u>Sierra Nevada Brewery</u>
Using 1MW of installed Molten Carbonate Fuel Cells operating on a combination of digestor gas (from the beer brewing process) and natural gas, this facility can produce electricty and heat for the brewery and attached bottling plant. The major thermal load on-site is to keep the brewing tanks at appropriate temperatures.

<u>NetApp Data Center</u>
Using 1.125 MW of Hess Microgen natural gas fired reciprocating engine-generators, with exhaust gas and jacket water heat recovery attached to over 300 tons of of adsorption chillers, this combined cooling and power system provides electricity and cooling to a data center with a 1,200 kW peak electrical load.

<u>Kaiser Permanente Hayward Hospital</u>
With 180kW of Tecogen natural gas fired reciprocating engine-generators this CHP system generates steam for space heating, and hot water for a city hospital.

For all sites, similar assumptions are made about the economic and technological constraints of the power generation system. Using the Distributed Energy Resource Customer Adoption Model (DER-CAM) developed at the Lawrence Berkeley National Laboratory, we model three representative scenarios and find the optimal operation scheduling, yearly energy cost, and energy technology investments for each scenario below:

<u>Scenario 1</u>
Diesel generators and CHP/CCHP equipment as installed in the current facility. Scenario 1 represents a baseline forced investment in currently installed energy equipment.

<u>Scenario 2</u>
Existing CHP equipment installed with blackout ride-through capability to replace approximately the same capacity of diesel generators. In Scenario 2 the cost of the

replaced diesel units is saved, however additional capital cost for the controls and switchgear for blackout ride-through capability is necessary.

Scenario 3
Fully optimized site analysis, allowing DER-CAM to specify the number of diesel and CHP/CCHP units (with blackout ride-through capability) that should be installed ignoring any constraints on backup generation. Scenario 3 allows DER-CAM to optimize scheduling and number of generation units from the currently available technologies at a particular site.

The results of this analysis, using real data to model the optimal schedulding of hypothetical and actual CHP systems for a brewery, data center, and hospital, lead to some interesting conclusions. First, facilities with high heating loads will typically prove to be the most appropriate for CHP installation from a purely economic standpoint. Second, absorption/adsorption cooling systems may only be economically feasible if the technology for these chillers can increase above current best system efficiency. At a coefficient of performance (COP) of 0.8, for instance, an adsorption chiller paired with a natural gas generator with waste heat recovery at a facility with large cooling loads, like a data center, will cost no less on a yearly basis than purchasing electricity and natural gas directly from a utility.

Third, at marginal additional cost, if the reliability of CHP systems proves to be at least as high as diesel generators (which we expect to be the case), the CHP system could replace the diesel generator at little or no additional cost. This is true if the thermal to electric (relative) load of those facilities was already high enough to economically justify a CHP system. Last, in terms of greenhouse gas emissions, the modeled CHP and CCHP systems provide some degree of decreased emissions relative to systems with less CHP installed. The emission reduction can be up to 10% in the optimized case (Scenario 3) in the application with the highest relative thermal load, in this case the hospital.

Although these results should be qualified because they are only based on the three case studies, the general results and lessons learned are expected to be applicable across a broad range of potential and existing CCHP systems.

Introduction

This "Assessment of Combined Heat and Power Premium Power Applications in California" analyzes the prospects for combined heat and power (CHP) systems to provide high reliability power for customer sites, as well as improved energy efficiency and economic benefits. Through a series of three case studies, key trade-offs are analyzed with regard to the provision of black-out ridethrough capability with the CHP systems and the resutling ability to avoid the need for at least some diesel backup generator capacity located at the case study sites.

Each of the selected sites currently have a CHP or combined heating, cooling, and power (CCHP) system[1] in addition to diesel backup generators. In all cases the CHP/CCHP system have a small fraction of the electrical capacity of the diesel generators. Although none of the selected sites currently have the ability to run the CHP systems as emergency backup power, all could be retrofitted to provide this blackout ride-through capability, and new CHP systems can be installed with this capability.

This report presents the details of the analysis and the results, and finishes by drawing some general conclusions. First, the structure and of the Pacific Region Combined Heat and Power Application Center (PRAC) is briefly described.

The Pacific Region Combined Heat and Power Application Center

The Pacific Region Combined Heat and Power Application Center (PRAC) was established in 2003 to foster the development of CHP in the Pacific region and to address knowledge gaps and other market failures that may be preventing the optimal expansion of CHP in the region. The primary sponsors of the PRAC are the U.S. Department of Energy and the California Energy Commission.

The PRAC features a collaborative structure among UC Berkeley (UCB), UC Irvine (UCI), and San Diego State University (SDSU). Each university provides some unique capabilities and resources to the center. The primary groups involved on the three campuses are the Energy and Resources Group at UCB, the Advanced Power and Energy Program at UCI, and the Industrial Assessment Center at SDSU. The PRAC is led by three co-directors (Tim Lipman, UCB; Vince McDonell, UCI; Asfaw Beyene, SDSU) and two additional principal investigators (Dan Kammen, UCB; Scott Samuelsen, UCI). For more information on the activities of the PRAC, visit the following website: http://www.chpcenterpr.org.

The PRAC has established strategic alliances with key partners in the region. These include three groups that work closely with each "node" of the center -- the Lawrence Berkeley National Laboratory, Sempra Energy, and the California Center for Sustainable Energy (formerly known as the San Diego Regional Energy Office) – and various other groups that are involved less directly. These additional groups work collaboratively with the PRAC to leverage activities and expand the effectiveness of the centers operations.

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[1] Most CCHP locations that are using waste heat for cooling also use some of the waste heat directly for water or space heating, at least during the cooler months when the cooling loads are lower. The NetApp data center is somewhat unusual in that all of the waste heat is used to drive the adsorption chillers, making it a "combined cooling and power" (CCP) application, rather than a more usual CCHP "trigeneration" system.

CHP Premium Power Applications and Opportunities

There is great deal of interest in redundant systems for distributed power generation in a number of industries where the cost of power and more importantly power interruptions is substantial. These so called *premium power* applications for CHP systems are the focus of this analysis. Some examples of such facilities are manufacturing plants, data centers, hospitals, and nursing homes. Premium power applications are characterized by their need for backup power in the event of a utility power outage. These backup systems are traditionally diesel generators and increasingly other CCHP systems are being installed at these sites. Such systems typically consist of on-site generation fueled by either natural gas or solar energy that produce electricity and supply thermal energy for cooling and heating loads. These CCHP systems can also act as backup generators in some cases, thus obviating the need for diesel backup generators. In this paper we analyze the economic feasibility of CCHP for premium power applications.

Modeling and DER-CAM Overview

For the purposes of this analysis we chose three sites with existing Combined Heat and Power (CHP) or Combined Cooling, Heating, and Power (CCHP) systems in place which also had diesel backup generators. As the basis for an economic analysis of these sites, we used the Distributed Energy Resources Customer Adoption Model (DER-CAM) being developed at the Lawrence Berkeley National Laboratory.

DER-CAM is an economic model of customer DER adoption implemented in the General Algebraic Modeling System (GAMS) optimization software. DER-CAM's goal is to minimize the cost of supplying electric and heat loads of a specific customer site by optimizing the installation and operation of distributed generation, combined heat and power, and thermally activated cooling equipment. In other words, the focus of this work is primarily economic. To achieve this objective, the following issues must be addressed:

- Which is the lowest-cost combination of distributed generation technologies that a specific customer can install?
- What is the appropriate level of installed capacity of these technologies that minimizes cost?
- How should the installed capacity be operated so as to minimize the total customer energy bill?

With the assumption that the customer desires to install distributed generation to minimize the cost of energy consumed on site, it is possible to determine the technologies and capacity the customer is likely to install and to predict when the customer will be self-generating electricity and/ or transacting with the power grid, and likewise when purchasing fuel or using recovered heat.

The DER-CAM model chooses which Distributed Generation (DG) and/or CHP technologies a customer should adopt and how that technology should be operated based on specific site load and price information, and performance data for available equipment options. The inputs to and outputs from DER-CAM are illustrated below.

Key inputs into the model are:

- the customer's end-use load profiles (typically for space heat, hot water, gas only, cooling, and electricity only)
- the customer's default electricity tariff, natural gas prices, and other relevant price data
- the capital, operating and maintenance (O&M), and fuel costs of the various available technologies, together with the interest rate on customer investment
- the basic physical characteristics of alternative generating, heat recovery and cooling technologies, including the thermal-electric ratio that determines how much residual heat is available as a function of generator electric output.

Outputs to be determined by the optimization model are:

- the capacities of DG and CHP technology or combination of technologies to be installed
- when and how much of the installed capacity will be running
- the total cost of supplying the electric and heat loads.

Key DER-CAM assumptions are:

- customer decisions are made based only on direct economic criteria (in other words, the only possible benefit is a reduction in the customer's energy bills);
- no deterioration in output or efficiency during the lifetime of the equipment is considered, and start-up and other ramping constraints are not included;
- reliability and power quality benefits, as well as economies of scale in O&M costs for multiple units of the same technology are not directly taken into account; and
- possible reliability or power quality improvements accruing to customers are not explicitly considered.

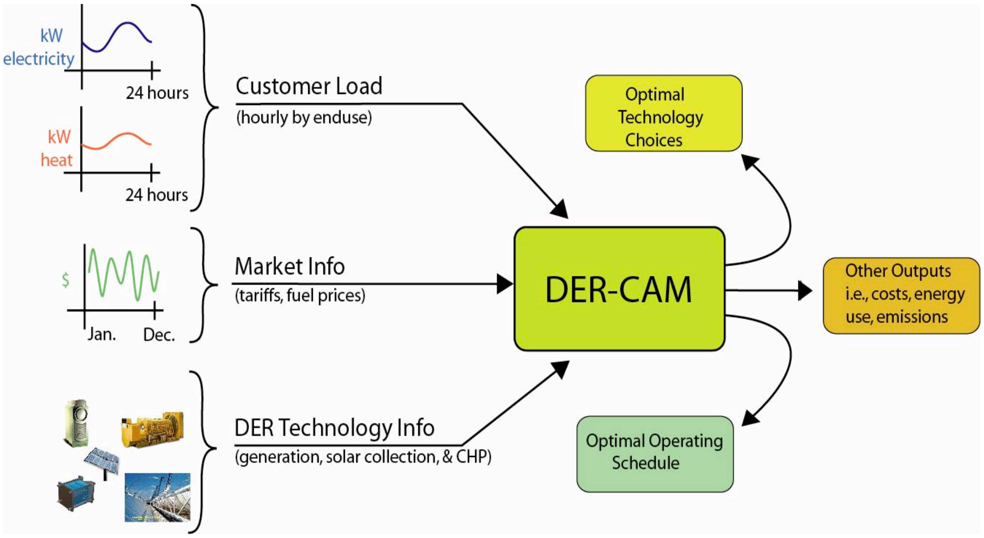

Figure 1: DER-CAM Structure [Stadler et al., 2008a]

We note that a more recent version of DER-CAM has been developed that includes consideration of reliability and power quality improvements and other benefits to the CHP or microgrid system host site. See Stadler et al. [2008b] for details.

<u>Simultaneous Optimization Approach</u>
The next figure shows a high-level schematic of the energy flow modeled in DER-CAM. Possible energy inputs to the site are solar insolation, utility electricity and natural gas. For a given DG investment decision, DER-CAM selects the optimal combination of utility purchase and on-site generation required to meet the site's end-use loads at each time step. The model allows that:

1) electricity-only loads (e.g. lighting and office equipment) can only be met by electricity;
2) cooling loads can be met either by electricity or by heat (via absorption / adsorption chiller);
3) hot water and space heating loads can be met either by recovered heat or by natural gas; and
4) natural gas-only loads (e.g. mostly cooking) can only be met by natural gas.

With these constraints, the model then attempts to find the best strategy for meeting the various energy needs at the lowest cost [Stadler et al., 2008a].

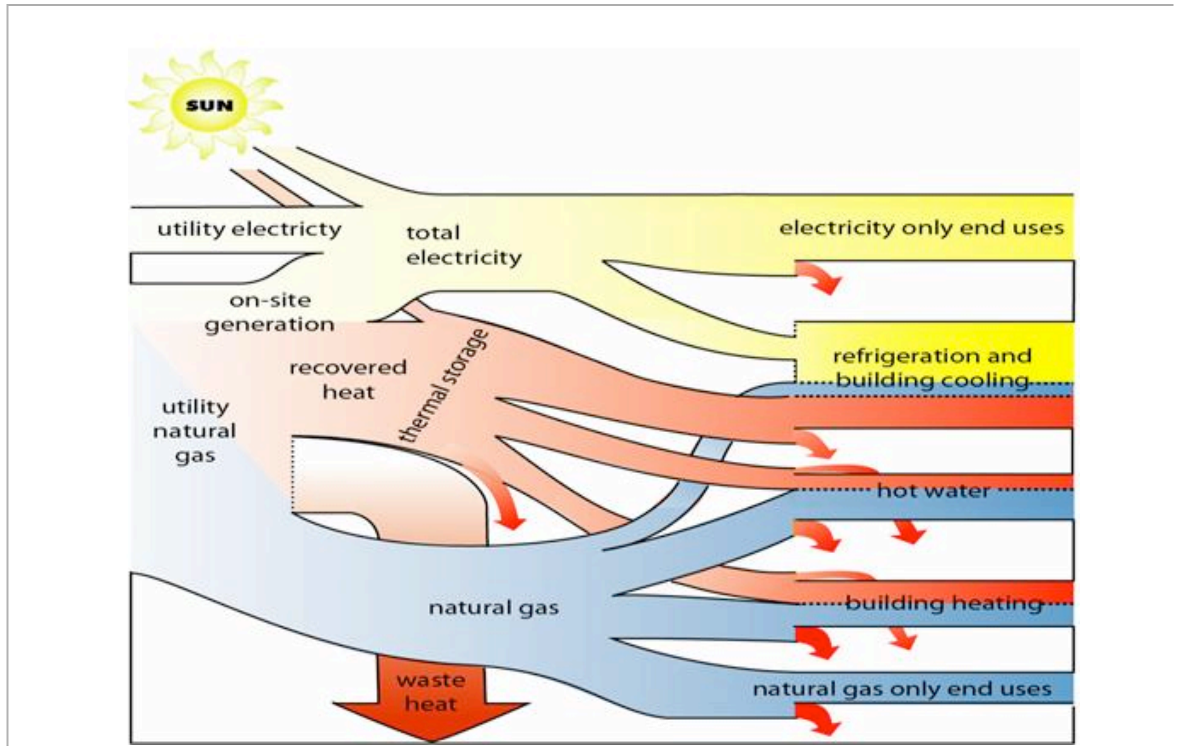

Figure 2 [Stadler et al., 2008a]

Selected CHP Analysis Sites

Each of the selected sites currently have a CHP or CCHP system in addition to diesel backup generators. In all cases the CHP/CCHP system have a small fraction of the electrical capacity of the diesel generators. Although none of the selected sites currently have the ability to run the CHP systems as emergency backup power, all could be retrofitted to provide this blackout ride-through capability, and new CCHP systems can be installed with this capability. The following three sites/systems were used for this analysis:

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With 180kW of Tecogen natural gas fired reciprocating engine-generators this CHP system generates steam for space heating, and hot water for a city hospital.

Key Technical and Economic Modeling Assumptions

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<u>Scenario 3</u>
Fully optimized site analysis, allowing DER-CAM to specify the number of diesel and CHP/CCHP units (with blackout ride-through capability) that should be installed ignoring any constraints on backup generation. Scenario 3 allows DER-CAM to optimize scheduling and number of generation units from the currently available technologies at a particular site.

Hardware data sheets and historical load data, not building models, form the basis for demand at each site. Average weekend and weekday loads for each month are extrapolations of this data and input to DER-CAM. For all sites, 2006 load data is used when available, but due to inavalibility some 2007 and 2008 data is supplemented in the Kaiser and NetApp models to fill in the gaps in 2006 data. Weekday, weekend and seasonal loads are appropriately aligned in all sets of merged data from multiple years so that seasonal and weekly variations are properly reflected in the data input to DER-CAM (Appendix A contains load data).

Capital cost inputs for all CHP/CCHP equipment and diesel generators are based on actual costs of installation for Sierra Nevada and NetApp, ignoring any state or federal rebates or incentives. Both construction projects were completed within the last 4 years. Capital costs for the Kaiser facility is based on a quote for the average cost of a nearly equivalent system with modern equipment [Tecogen, 2008], owing to the older age of the Kaiser system. This quote also contains a comparison to a similar system installed with blackout ride-through capability, thus allowing easy comparison of the two configurations. Diesel generator equipment costs are also based on in industry price quote [Peterson Power, 2008]. Service contracts to determine variable and fixed O&M costs are either real costs or estimates from the contractors who installed the equipment.

In order to accurately model the yearly energy cost for each facility, a five percent interest rate is assumed per annum. Fuel costs for diesel, natural gas and electricity in the model are based on prices paid by Sierra Nevada in 2006, and 2008 prices for the Kaiser and NetApp facilities. Kaiser and NetApp electricity and diesel prices are based on the tariffs for May, 2008 [PG&E,

2008] and natural gas prices on the January-May historical prices and the futures spot market prices adjusted for location in the period from June-December 2008 [IKUN, 2008].

Efficiency of the chillers, CHP units, and diesel generators is based on actual power production and fuel consumption when possible, and from manufacturer's data sheets in all other cases. The overall macrogrid electrical conversion efficiency was assumed to be 34%. To determine the relative carbon emissions of each proposed scenario, a value for the marginal Northern California electrical grid carbon intensity of 0.14 kg CO_2/kWh is used [Stadler et al., 2008a].

Model Data and Analysis Procedures

In order to meaningfully be able to compare CHP/CCHP systems to backup generators, the increased cost of blackout ride-through capability is incorporated into the capital cost of the CHP/CCHP technology for Scenario 2 and Scenario 3 at each site. The quotes/estimates we received (from Tecogen and Thomson Technology) allow us to put a price on this black-out ridethrough capability at $75-$200/kW for engine generator models. However, in some situations where much of the electronics/switchgear are already in place, the cost of adding the black-out ridethrough capabilities could be much less. For example, one site reported that adding this capability for its existing 1.2 MW microturbine system would cost on the order of $10,000-15,000, or more like $10/kW.

We do not explicitly find the average cost of adding this capability to a fuel cell system such as the one installed at Sierra Nevada. This cost would depend much more greatly on how steady the load was when the fuel cell was supplying back-up power because the ramp rate and min/max capacity range of a fuel cell is limited. In such a case, a battery system, or Uninterruptible Power Supply (UPS) would probably be necessary to smooth transient loads. We assume a $200/kW(capacity) price premium for this blackout ride-through capability across both the fuel cell and engine-generator CHP units. The actual cost of doing this for a fuel cell system could be greater depending on the factors mentioned above.

In addition, other problems can be encountered with CHP as emergency backup. For instance, at the NetApp facility, the UPS, combined with the electromechanical controls on the Hess Microgen unit contributed to a problem where the load was being dumped too quickly on the Microgen units, causing them to shut down [Niblett, Devcon; Renne, NetApp]. A different UPS, or more sophisticated load ramping algorithms on the CHP units could improve blackout ride-through capability in this scenario.

Capacity factor for each facility is based on actual average runtime in 2006 when the systems were intended to be operating continuously. For NetApp, data for a representative year is unavailable so continuous operation is assumed. At the other two facilities, actual runtime was considerably less than the intended operating schedule which dictated 8760 hours/year (24hrs * 365 days/year). Sierra Nevada's fuel cells only operated an average of 6640 hours/year, and Kaiser's CHP units for 6648 hours/year, just over 75% of the time they were scheduled to operate.

Although valuation of reliability differences between diesel generators and other CHP technology was considered in our analysis, the reliability difference of switching from diesel generators to CHP units for emergency power is difficult to quantify and relatively small. Based on average cost per outage and reliability event data for industrial/commercial facilities of this size, the cost of all outages over the course of a year would be:

System Average Interruption Frequency Index (SAIFI) * Cost per Sustained Outage + Momentary Average Interruption Frequency Index (MAIFI) * Cost per Momentary Outage = 1.3*$4.111 + 2.3*1881 = $9,671

Reliability and cost per outage data for California for this example is taken from LaCommare [2004]. Given that there is a small fraction of generators that fail during emergency backup operation, only a small fraction of this $9,671 could be recovered by increased backup system reliability. Since the annual energy costs exceed $1 million for each, this effect on the order of $1,000 in value is "in the noise" and certainly shouldn't affect the relative costs of any of the scenarios compared. Therefore, any difference in diesel and CHP backup generator reliability is ignored in this analysis.

Summary of Modeling Results

The results in Tables 1-3 and Figures 3-5 show there is significant room for savings in both the technologies chosen, and the scheduling of on-site generation at the facilities considered. By comparing the carbon emissions and yearly energy cost of scenario 3 to scenario 1 for each of the three facilities, one can see if currently installed CHP technologies are economically and environmentally favorable at each site. For Sierra Nevada and NetApp the CHP/CCHP system without state incentives is not, from a purely economic standpoint, the best investment. Yet for Kaiser, increasing the total installed capacity of CHP units from 180 kW to a total 600 kW of on-site generation would provide the lowest yearly energy cost. Not surprisingly, due to their inherent efficiency (heat plus electricity generation), scenarios with the greatest number of natural gas CHP technologies had the lowest carbon emissions. For Kaiser Hayward, installing 600 kW of CHP units with blackout ride-through capability would provide an ~10% reduction in carbon emissions, and ~3% cost reduction over the optimal scheduling of their currently installed system.

In the Sierra Nevada and NetApp cases, in the absence of any economic incentives to install CHP the least expensive method to power the facility would be to buy all electricity and natural gas from the utility company. However, this would correspond to a greater than 12% increase in carbon emissions for Sierra Nevada, and ~1% increase in carbon emissions for NetApp compared to optimal scheduling of their currently installed generation technology.

Table 1: Sierra Nevada Brewery Overall Results (2006 Prices)

	Scenario 1	**Scenario 2**	**Scenario 3**
Goal Function Value (= Total Annual Energy Costs) ($)	2,607401	2,586,022	2,044,065
Installed Units for Each Available Technology			
200 kW natural gas fuel cell CHP unit	4	4	0
750 kW diesel generator	3	2	0
Emissions			
Annual Total Carbon Emissions (kg)	2,787,459	2,786,924	3,127,592

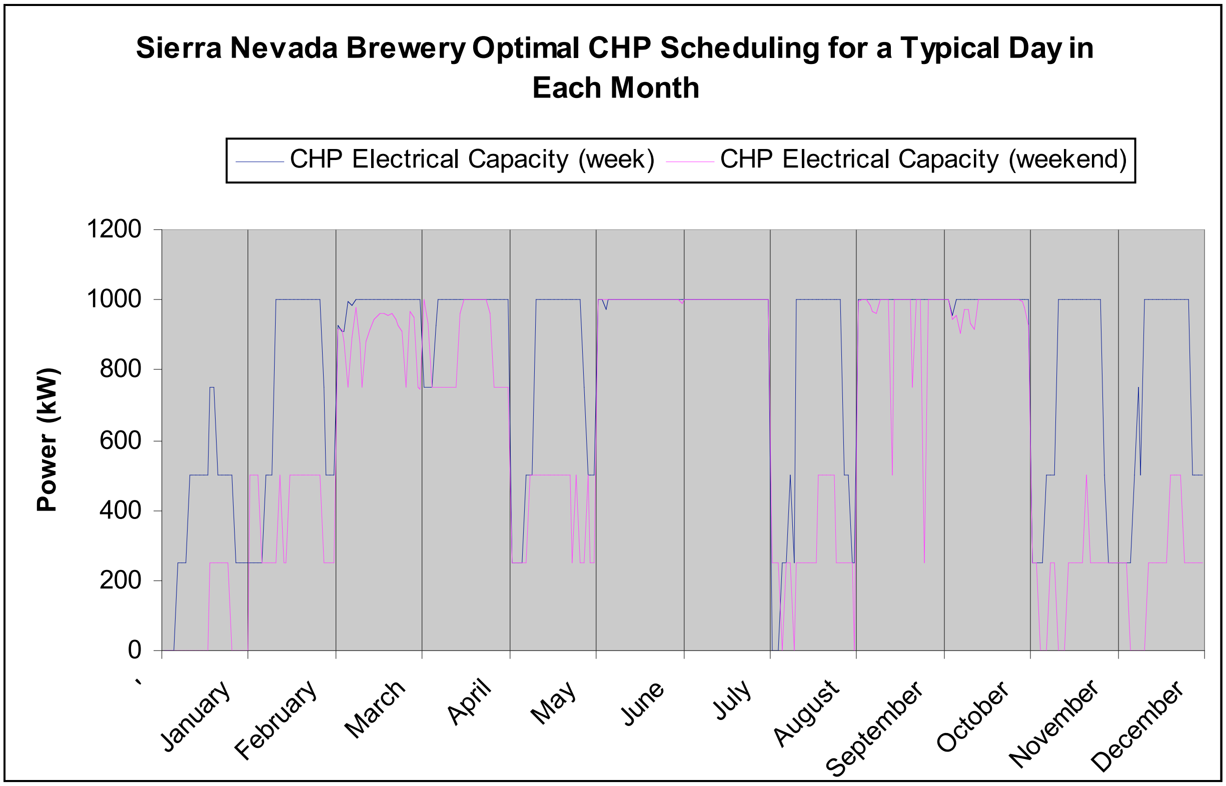

Figure 3: Optimal Scheduling of CHP for the Sierra Nevada Brewery
(Time period for each day's hourly interval data is 0:00H to 23:00H)

Table 2: NetApp Data Center Overall Results (2008 Prices)

	Scenario 1	Scenario 2	Scenario 3
Goal Function Value (= Total Annual Energy Costs) ($)	1,630,858	2,219,106	1,061,670
Installed Units for Each Available Technology			
2 MW diesel generator	2	1	0
375 kW natural gas CCHP unit	3	6	0
Emissions			
Annual Total Carbon Emissions (kg)	1,369,578	1,369,421	1,383,748

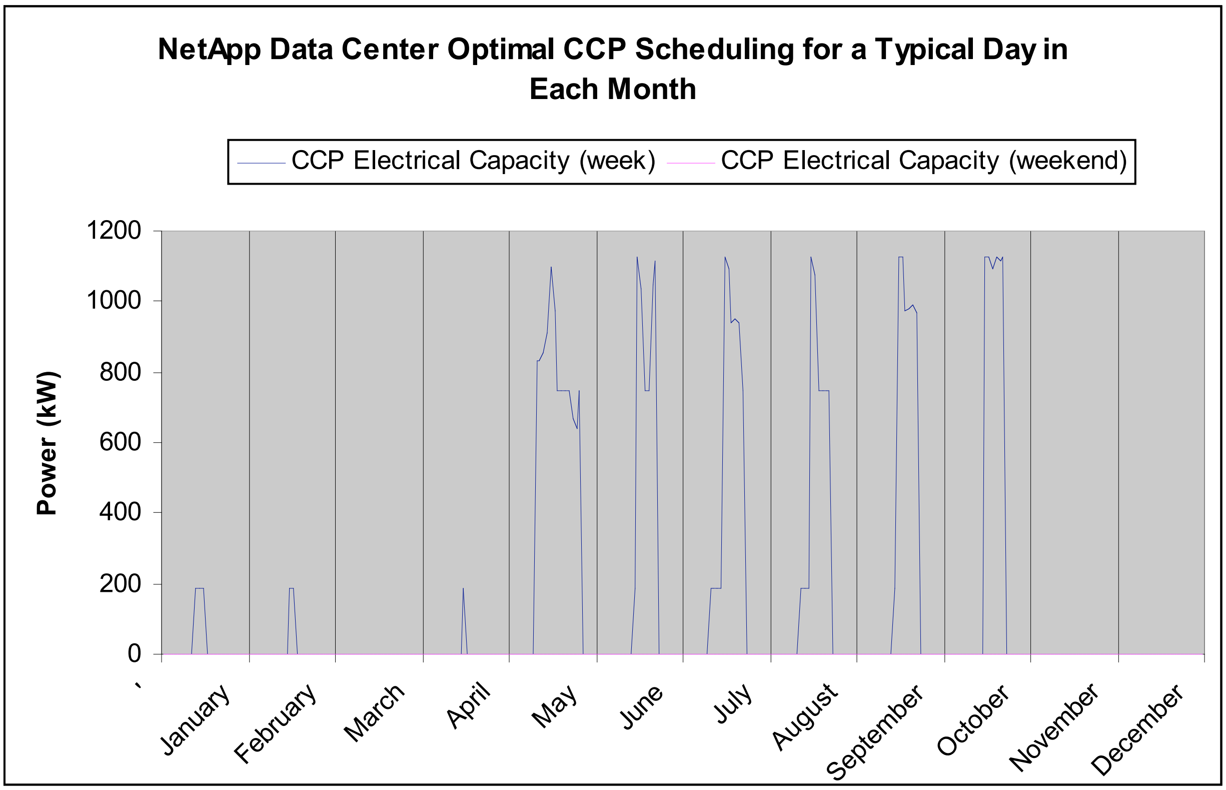

Figure 4: Optimal Scheduling of CHP for the NetApp Data Center
(Time period for each day's hourly interval data is 0:00H to 23:00H)

Table 3: Kaiser Hayward Hospital Overall Results (2008 Prices)

	Scenario 1	Scenario 2	Scenario 3
Goal Function Value (= Total Annual Energy Costs) ($)	1,773,688	1,766,464	1,721,870
Installed Units for Each Available Technology			
350 kW diesel generator	2	2	0
260 kW diesel generator	1	0	0
60 kW natural gas CHP unit	3	4	10
Emissions			
Annual Total Carbon Emissions (kg)	2,199,106	2,169,773	1,980,507

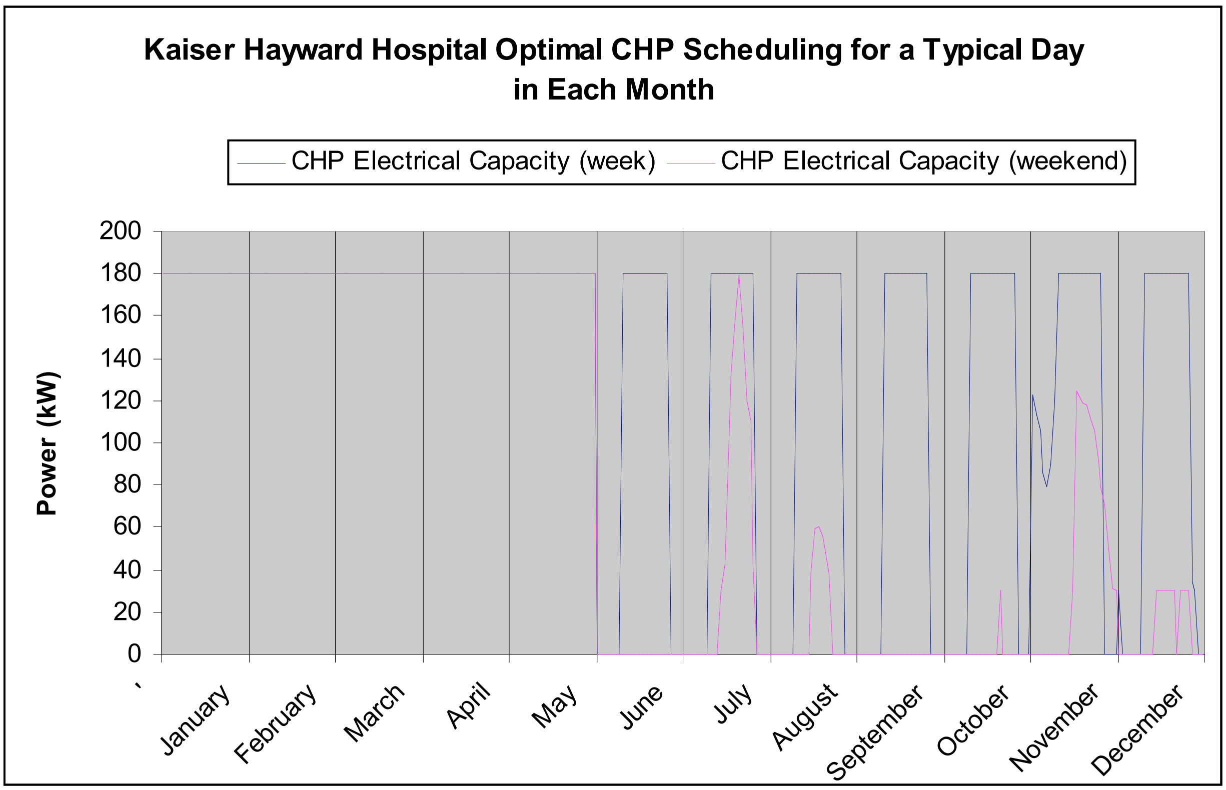

Figure 5: Optimal Scheduling of CHP for the Kaiser Hayward Hospital
(Time period for each day's hourly interval data is 0:00H to 23:00H)

Comparing Scenario 2 to Scenario 1 shows the benefit/cost of substituting for diesel generation with a nearly equivalent capacity of CHP units. In Scenario 2 it is assumed that the CHP/CCHP system was installed initially with the capability for blackout ride-through capability and no cost was incurred for the substituted diesel generators. For Sierra Nevada and NetApp, the carbon emissions savings for this substitution would only be a few hundred kilograms annually; a nearly break-even proposition. For NetApp, however, the cost of installing additional CCHP units to replace the diesel generators would be substantial, adding ~36% to the yearly energy cost compared to the current system. Our analysis shows no clear economic or environmental incentive to provide blackout ride-through capability for Sierra Nevada or NetApp. For Kaiser Hayward, however, substituting for one of the 260 kW diesel generators with 240 kW of natural gas reciprocating engine CHP units with blackout ride-through capability would provide a <0.5% reduction in annual energy cost and a 1.3% reduction in carbon emissions compared to the existing system; a small but significant difference.

In terms of optimal scheduling of the various CHP technologies and facilities considered, it is not surprising that midday and summer operation provided the most economic incentive for the data center, where waste heat was used for cooling. For the hospital, with higher heating loads in the winter, the CHP units were scheduled to run throughout that period on both week days and weekend days. All other things being equal, facilities with steady electrical demand would have a lesser benefit from installing CHP technologies than will those facilities with peaking demand during the middle of the day when electrical prices are at their highest. These peak pricing times are exactly when operating the CHP units will provide the most economic benefit. For instance, because of the steady electrical demand during the weekends compared to the weekdays for the data center, the optimal scheduling for the CCHP system on weekends was to remain always off, as purchase of electricity to drive compressor chillers would be less expensive than generating electricity with the CCHP system while providing supplemental adsorption cooling.

Caveats and Directions for Future Work

It is important to recognize the limitations and strengths of the type of economic optimization performed in this analysis. Because the objective of this optimization is to minimize total yearly energy costs, economic “externalities,” many of them environmental, are ignored. Although the model does evaluate the direct carbon dioxide emissions from all energy generation technology, it does not optimize for this parameter by assigning it a monetary value. Additionally, embedded energy in manufacturing / transportation and life cycle greenhouse gas (GHG) emissions of the various energy generation technologies are ignored. Future work to look more seriously at the relative GHG lifecyle emissions from each of these technologies could motivate an optimization based on some combination of economic and environmental parameters.

Also not included in this analysis are the various state and federal incentives for installing CHP technologies, many of which were used in the installation of the systems at the facilities we analyzed (Self-Generation Incentive Program for instance). Because these incentives vary widely from state to state, can also vary from year to year, and also because they do not represent a uniform market discount, these incentives were not included. We note that at present the SGIP program in California only provides incentives for fuel cell technologies as CHP resources, and is not providing an incentive for combustion technologies.

In addition to the factors above, there were many approximations and concessions made in constructing the load profiles for a couple of the facilities selected. Due to incomplete availability of data for NetApp, the cooling load was assumed to be negligible in the coldest months of the year (December through February) when it is assumed that outside air economizers can provide the vast majority of cooling. The electrical work used to power the fans for this cooling source was also uniformly ignored. In addition, because a composite of load data from the years 2006 and 2007 were used in the Kaiser and Netapp facilities some of the ‘typical’ load profiles input to our economic model may be skewed slightly because in some cases cooling load is coming from a month of data in for instance 2007, while CCHP system output may be from the same month in 2006. Because of the methodology used, the typical week/weekend day loads for each month (as shown in Appendix A) are not strictly an average of every week/weekend day, but instead the actual profile for a day chosen because it most closely matched the average week/weekend daily load for that particular month.

This methodology attempts to capture the complicated transient loads that may be present in a typical day, but hidden on average. This methodology must be considered in viewing the modeled results, especially the optimal scheduling of the CHP system (Figures 3-5), which should therefore be taken as guidelines, not to be strictly followed in actual scheduling of the CHP systems. Frequent repeated startups and shutdowns will obviously be detrimental to the longevity of any CHP/CCHP system and should be avoided.

Finally, this analysis did not, by any means, try to evaluate all potential CCHP technologies, and in fact, some obvious technologies, such as solar were not even considered because they were not installed at any of the selected sites. In fact, no attempt to assess the relative benefit of any CCHP technologies not already installed at the sites evaluated was made (with the obvious exception of black-out ridethrough capability; the addition of which was considered in scenario 2 for all sites). A comprehensive analysis and optimization over all possible technology choices using DER-CAM could guide future CCHP technology selection for premium power applications, although the costs from site to site can vary dramatically depending on the mechanical and electrical upgrades that may be needed for any CCHP installation.

Conclusions

Through comparison of representative scenarios for each of three premium power CHP/CCHP sites (a brewery, a data center, and a hospital) some broad observations can be made about the economic and environmental effects of such installations. It is shown that the economically optimal (i.e. lowest cost w/out state incentives) technology investment for two of the sites is to not invest in the CHP systems at all. For both the brewery and data center, the cost of the CHP system is either too great (e.g. fuel cells), or the system is too inefficient (e.g. adsorption chillers) compared to the price of electricity and natural gas from the utilities to justify installing and operating such a system. For the hospital, however, the currently installed CHP system is an underinvestment, and due to the large and steady heat demands, a greater investment in CHP could significantly benefit the facility in terms of both cost savings and reduction in carbon dioxide emissions.

This analysis also looked at the possibility of replacing existing diesel generation with CCHP systems with blackout ride-through capability. For the brewery, the additional yearly cost and emissions savings from this option would be negligible, assuming a suitable load could be islanded and the capital cost of installing such capability would only be $200/kW beyond that of the existing CHP system. For the hospital, a slight benefit could be achieved by replacing the some diesel generators with natural gas fired reciprocating engine CHP system; this would be on the order of a 1% yearly energy cost and carbon emissions reduction. It might be interesting to look at the proposition of replacing all the diesel generators with these these units in this case. For the data center, however, a negligible environmental benefit was shown and a significant yearly energy cost increase (36%) was predicted by this model.

Overall, no matter what technology was chosen, the underlying theme is that a facility's load profile will determine the relative economic and environmental efficacy that any CHP system would achieve. A system with a high cooling load and no heating load (such as a data center) has comparitively lesser benefit than one with a large heating load (such as a hospital) due to the relatively low-cost of heat recovery systems as compared to adsorption/absorption chiller systems. Expensive and efficient electrical generation technologies (i.e. fuel cells) provide no better performance for facilities with high heat loads (such as a hospital or brewery), than less expensive natural gas fired reciprocating engine technology with heat recovery, but they do provide environmental benefits. Optimal scheduling of any selected technology will be largely determined by the time period of highest thermal demand and highest electrical pricing, with the latter being the dominant factor in determining the most cost effective operation schedule. Of course, running CHP systems at the time of highest electrical pricing will mean running them at the time of the day when ambient air pollution is the worst, and is therefore not recommended in urban and suburban settings.

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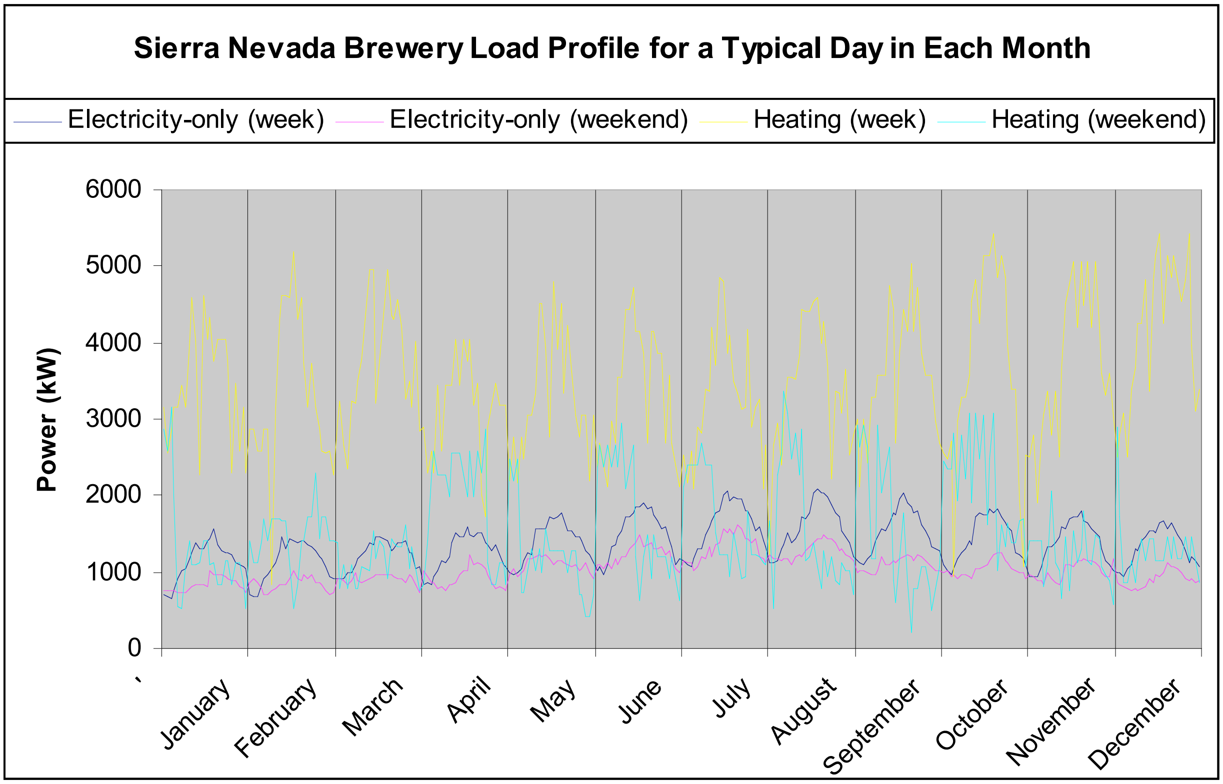
Appendix A – Load Data and DER-CAM Inputs / Results for Each Scenario



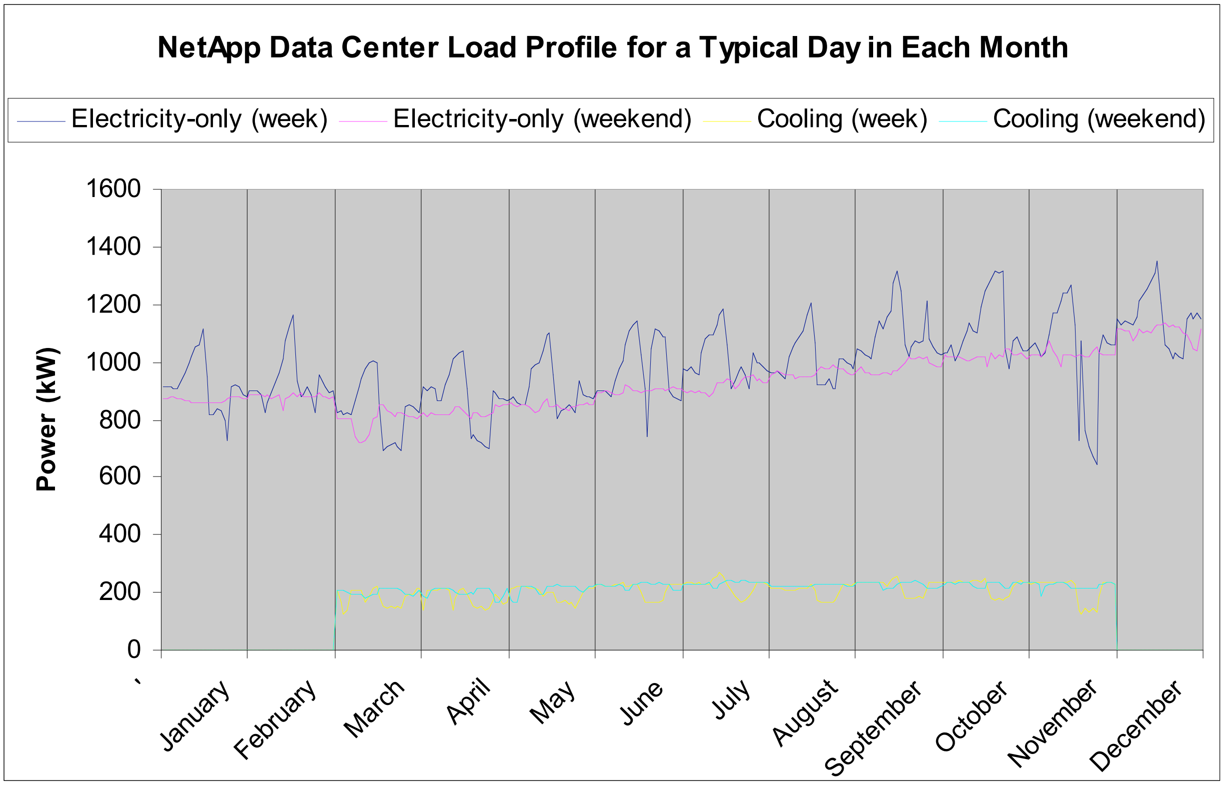
Sierra Nevada DER-CAM Model Summary and Results

+++++++++Summary+++++++++	Scenario 1	Scenario 2	Scenario 3
Goal Function Value (= Total Annual Energy Costs minus Electricity Sales) ($)	2,607,401	2,586,022	2,044,065
Installed Capacity (kW)	3,250	2,500	0
Installed Capacity: Electricity-only (kW)	2,250	1,500	0
Installed Capacity: Electric/Heating (kW)	1,000	1,000	0
Installed Capacity: Electric/Heating/Cooling (kW)	0	0	0
Installed Capacity: Photovoltaics (kW)	0	0	0
Installed Capacity: Natural Gas for I.C.E. (reciprocating engines) (kW)	0	0	0
Installed Capacity: Microturbines (kW)	0	0	0
Installed Capacity: Fuel Cells (kW)	1,000	1,000	0
Electricity Generated Onsite (kWh/a)	6,629,625	6,622,875	0
Fraction of electricity generated onsite (without absorption chiller offset)	0.59	0.59	0
Effective Fraction of electricity generated onsite (includes absorption chiller offset)	0.59	0.59	0
Heating Load Offset by CHP (kWh/a)	2,198,545	2,198,794	0
Cooling Load Offset by CHP (kWh/a)	0	0	0
Utility Electricity Consumption (kWh/a)	4,527,078	4,533,828	1,1156,703
Utility Natural Gas Consumption (kWh/a)	43,635,873	4,3637,219	31,744,791
Total Fuel Consumption (onsite plus fuel for macrogrid electricity) (kWh/a)	5,6950,809	56,972,008	64,558,623

+++++++++Efficiencies and Fractions+++++++++			
Efficiency of Entire Energy Utilization (Onsite and Purchase)	0.64	0.64	0.57
Natural Gas DER System Efficiency (Elec + Heat)	0.63	0.63	UNDF
Natural Gas DER System Efficiency (Federal Regulatory Commission - FERC Definition)	0.55	0.55	UNDF
Fraction of Energy Demand Met On-Site	0.23	0.23	0
Fraction of Electricity-Only End-Use Met by On-Site Generation	0.59	0.59	0
Fraction of Cooling End-Use Met by On-Site Generation	UNDF	UNDF	UNDF
Fraction of Cooling End-Use Met by Absorption Chiller	UNDF	UNDF	UNDF
Fraction of Cooling End-Use Met by Natural Gas	UNDF	UNDF	UNDF
Fraction of Space-Heating End-Use Met by CHP	0.07	0.07	0
Fraction of Space-Heating End-Use Met by Natural Gas	0.93	0.93	1
Fraction of Water-Heating End-Use Met by CHP	UNDF	UNDF	UNDF
Fraction of Water-Heating End-Use Met by Natural Gas	UNDF	UNDF	UNDF
Fraction of Natural Gas-Only End-Use Met by Natural Gas	UNDF	UNDF	UNDF
+++++++++Model 0ptions+++++++++			
Invest	1	1	1
Sales	0	0	0
StandbyOpt	0	0	0
VaryPrice	0	0	0
CHP	0	0	0
CarbonTax	1	1	1
GasForCool	0	0	0
ForcedInvest	1	1	0
+++++++++Model Parameters+++++++++			
IntRate	0.05	0.05	0.05
Standby	0	0	0
Contrct	0	0	0
turnvar	0	0	0
CTax	0	0	0
MktCRate	0.14	0.14	0.14
macroeff	0.34	0.34	0.34
cooleff	0.13	0.13	0.13
MinEffic	0	0	0
Reliability	0.9	0.9	0.9
AvgCapacity	1,000	1,000	1,000
AbsFraction	0	0	0
m2	0	0	0

b2	0	0	0
m3	0	0	0
b3	0	0	0
BaseCaseCost	20,000,000	20,000,000	20,000,000
MaxPaybackPeriod	20	20	20
+++++++++Installed Units for each available Technology++++++++++++			
Available Technologies are technologies with MaxAnnualHour values greater than 0			
in table GenConstraints in folder Technology Data			
FC-------------00200	4	4	0
GT-------------01000	3	2	0
+++++++++Reports on an Annual Basis+++++++++			
Loads (All Numbers in kWh)			
1 kWh = 3412.14 BTU			
Annual Electricity-Only Load Demand	11,156,703	11,156,703	11,156,703
Annual Cooling Load Demand	0	0	0
Annual Space Heating Load	25,395,833	25,395,833	25,395,833
Annual Water Heating Load	0	0	0
Annual Natural Gas-Only Heating Load	0	0	0
Annual Total Energy Demand (kWh)	36,552,536	36,552,536	36,552,536
Generation (All Numbers in kWh)			
1 kWh = 3412.14 BTU			
Total Annual Electricity Generation On Site	6,629,625	6,622,875	0
Annual Electricity Generation On-Site to Meet Electricity-Only Load	6,629,625	6,622,875	0
Annual Electricity Generation On-Site to Meet Cooling Load	0	0	0
Annual On-Site Production of Energy (Electricity + Utilized Waste Heat + Natural Gas) (kWh)	8,388,461	8,381,910	0
Purchase (All Numbers in kWh)			
Annual Electricity Purchase to Meet Electricity-Only Load	4,527,078	4,533,828	1,1156,703
Annual Electricity Purchase to Meet Cooling Load	0	0	0
Natural Gas (All Numbers in kWh)			
Annual Natural Gas-Only Load which is met by Natural Gas	0	0	0
Annual Cooling Load which is met by Natural Gas,	0	0	0
Annual Space Heating Load which is met by Natural Gas	23,636,996	23,636,797	25,395,833

Annual Water Heating Load which is met by Natural Gas (kWh)	0	0	0
CHP (All Numbers in kWh)			
Annual Cooling Load which is met by Absorption Chiller	0	0	0
Annual Load of Water Heating which is met by CHP	0	0	0
Annual Load of Space Heating which is met by CHP	1,758,836	1,759,036	0
Energy Carriers			
Annual DER Natural Gas Purchases (kWh)	14,089,627	14,091,223	0
Annual NON DER Natural Gas Purchases (kWh)	29,546,246	29,545,997	31,744,791
Annual Net Gas Purchase (kWh)	43,635,873	43,637,219	31,744,791
Annual Total Gas Costs ($)	1156,728	1,157,517	852,172
Annual Net Diesel Purchase (kWh)	22,727	0	0
Annual Diesel Bill ($)	1,028	0	0
Emissions			
Annual On-site Carbon Emissions from Natural Gas DER (kg)	694,900	694,979	0
Annual On-site Carbon Emissions from Diesel DER (kg)	1,546	0	0
Annual On-site Carbon Emissions from Natural Gas (kg)	1,457,221	1,457,209	1,565,653
Annual Off-site Carbon Emissions (Macrogrid) (kg)	633,791	634,736	1,561,938
Annual Total Carbon Emissions (kg)	2,787,459	2,786,924	3,127,592



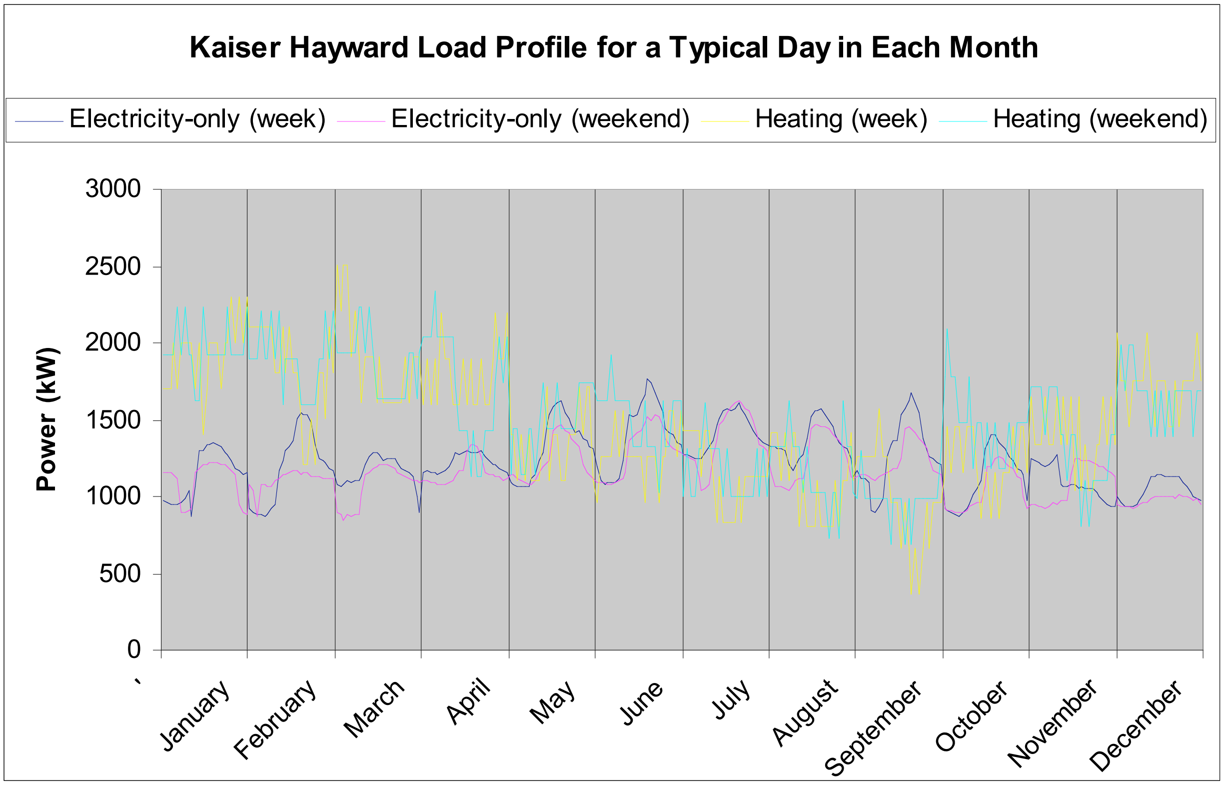
NetApp DER-CAM Model Summary and Results

+++++++++Summary+++++++++	Scenario 1	Scenario 2	Scenario 3
Goal Function Value (= Total Annual Energy Costs minus Electricity Sales) ($)	1,630,858	2,219,106	1,061,670
Installed Capacity (kW)	5,125	4,250	0
Installed Capacity: Electricity-only (kW)	4,000	2,000	0
Installed Capacity: Electric/Heating (kW)	0	0	0
Installed Capacity: Electric/Heating/Cooling (kW)	0	0	0
Installed Capacity: Photovoltaics (kW)	0	0	0
Installed Capacity: Natural Gas for I.C.E. (reciprocating engines) (kW)	1,125	2,250	0
Installed Capacity: Microturbines (kW)	0	0	0
Installed Capacity: Fuel Cells (kW)	0	0	0
Electricity Generated Onsite (kWh/a)	925,914	937,043	0
Fraction of electricity generated onsite (without absorption chiller offset)	0.1	0.1	0
Effective Fraction of electricity generated onsite (includes absorption chiller offset)	0.11	0.11	0
Heating Load Offset by CHP (kWh/a)	0	0	0
Cooling Load Offset by CHP (kWh/a)	163,743	165,619	0
Utility Electricity Consumption (kWh/a)	8,794,258	8,781,253	9,883,915
Utility Natural Gas Consumption (kWh/a)	2,805,801	2,839,524	0
Total Fuel Consumption (onsite plus fuel for macrogrid electricity) (kWh/a)	28671266	28,666,740	29,070,339

+++++++++Efficiencies and Fractions+++++++++			
Efficiency of Entire Energy Utilization (Onsite and Purchase)	0.34	0.34	0.34
Natural Gas DER System Efficiency (Elec + Heat)	0.78	0.78	UNDF
Natural Gas DER System Efficiency (Federal Regulatory Commission - FERC Definition)	0.55	0.55	UNDF
Fraction of Energy Demand Met On-Site	0.11	0.11	0
Fraction of Electricity-Only End-Use Met by On-Site Generation	0.1	0.11	0
Fraction of Cooling End-Use Met by On-Site Generation	0.03	0.02	0
Fraction of Cooling End-Use Met by Absorption Chiller	0.12	0.12	0
Fraction of Cooling End-Use Met by Natural Gas	0	0	0
Fraction of Space-Heating End-Use Met by CHP	UNDF	UNDF	UNDF
Fraction of Space-Heating End-Use Met by Natural Gas	UNDF	UNDF	UNDF
Fraction of Water-Heating End-Use Met by CHP	UNDF	UNDF	UNDF
Fraction of Water-Heating End-Use Met by Natural Gas	UNDF	UNDF	UNDF
Fraction of Natural Gas-Only End-Use Met by Natural Gas	UNDF	UNDF	UNDF
+++++++++Model 0ptions+++++++++			
Invest	1	1	1
Sales	0	0	0
StandbyOpt	0	0	0
VaryPrice	0	0	0
CHP	0	0	0
CarbonTax	1	1	1
GasForCool	0	0	0
ForcedInvest	1	1	0
+++++++++Model Parameters+++++++++			
IntRate	0.05	0.05	0.05
Standby	0	0	0
Contrct	0	0	0
turnvar	0	0	0
CTax	0	0	0
MktCRate	0.14	0.14	0.14
macroeff	0.34	0.34	0.34
cooleff	0.13	0.13	0.13
MinEffic	0	0	0
Reliability	0.9	0.9	0.9
AvgCapacity	1,000	1,000	1,000
AbsFraction	0	0	0
m2	0	0	0
b2	0	0	0

m3	0	0	0
b3	0	0	0
BaseCaseCost	20,000,000	20,000,000	20,000,000
MaxPaybackPeriod	20	20	20
+++++++++Installed Units for each available Technology++++++++++++			
Available Technologies are technologies with MaxAnnualHour values greater than 0			
in table GenConstraints in folder Technology Data			
GT-------------01000	2	1	0
NG-------------00200	3	6	0
+++++++++Reports on an Annual Basis+++++++++			
Loads (All Numbers in kWh)			
1 kWh = 3412.14 BTU			
Annual Electricity-Only Load Demand	8,501,995	8,501,995	8,501,995
Annual Cooling Load Demand	1,381,920	1,381,920	1,381,920
Annual Space Heating Load	0	0	0
Annual Water Heating Load	0	0	0
Annual Natural Gas-Only Heating Load	0	0	0
Annual Total Energy Demand (kWh)	9,883,915	9,883,915	9,883,915
Generation (All Numbers in kWh)			
1 kWh = 3412.14 BTU			
Total Annual Electricity Generation On Site	925,914	937,043	0
Annual Electricity Generation On-Site to Meet Electricity-Only Load	891,046	902,584	0
Annual Electricity Generation On-Site to Meet Cooling Load	34,868	34,459	0
Annual On-Site Production of Energy (Electricity + Utilized Waste Heat + Natural Gas) (kWh)	1089657.22	1102662	0
Purchase (All Numbers in kWh)			
Annual Electricity Purchase to Meet Electricity-Only Load	7,610,949	7,599,411	8,501,995
Annual Electricity Purchase to Meet Cooling Load	1,183,309	1,181,842	1,381,920
Natural Gas (All Numbers in kWh)			
Annual Natural Gas-Only Load which is met by Natural Gas	0	0	0
Annual Cooling Load which is met by Natural Gas,	0	0	0
Annual Space Heating Load which is met by Natural Gas	0	0	0
Annual Water Heating Load which is met by Natural Gas (kWh)	0	0	0

CHP (All Numbers in kWh)			
Annual Cooling Load which is met by Absorption Chiller	163,743	165,619	0
Annual Load of Water Heating which is met by CHP	0	0	0
Annual Load of Space Heating which is met by CHP	0	0	0
Energy Carriers			
Annual DER Natural Gas Purchases (kWh)	2,805,801	2,839,524	0
Annual NON DER Natural Gas Purchases (kWh)	0	0	0
Annual Net Gas Purchase (kWh)	2,805,801	2,839,524	0
Annual Total Gas Costs ($)	113,557	114,910	4,117.5
Annual Net Diesel Purchase (kWh)	0	0	0
Annual Diesel Bill ($)	0	0	0
Emissions			
Annual On-site Carbon Emissions from Natural Gas DER (kg)	138,382	140,045	0
Annual On-site Carbon Emissions from Diesel DER (kg)	0	0	0
Annual On-site Carbon Emissions from Natural Gas (kg)	0	0	0
Annual Off-site Carbon Emissions (Macrogrid) (kg)	1,231,196	1,229,375	1,383,748
Annual Total Carbon Emissions (kg)	1,369,578	1,369,421	1,383,748



Kaiser Hayward DER-CAM Model Summary and Results

+++++++++Summary+++++++++	Scenario 1	Scenario 2	Scenario 3
Goal Function Value (= Total Annual Energy Costs minus Electricity Sales) ($)	1,773,688	1,766,464	1,721,870
Installed Capacity (kW)	1140	940	600
Installed Capacity: Electricity-only (kW)	960	700	0
Installed Capacity: Electric/Heating (kW)	180	240	600
Installed Capacity: Electric/Heating/Cooling (kW)	0	0	0
Installed Capacity: Photovoltaics (kW)	0	0	0
Installed Capacity: Natural Gas for I.C.E. (reciprocating engines) (kW)	180	240	600
Installed Capacity: Microturbines (kW)	0	0	0
Installed Capacity: Fuel Cells (kW)	0	0	0
Electricity Generated Onsite (kWh/a)	1,042,695	1,422,194	3,897,462
Fraction of electricity generated onsite (without absorption chiller offset)	0.1	0.13	0.37
Effective Fraction of electricity generated onsite (includes absorption chiller offset)	0.1	0.13	0.37
Heating Load Offset by CHP (kWh/a)	1,995,719	2,721,818	7,416,044
Cooling Load Offset by CHP (kWh/a)	0	0	0
Utility Electricity Consumption (kWh/a)	9,530,707	9,151,208	6,675,940
Utility Natural Gas Consumption (kWh/a)	17,534,611	18,017,106	21,205,898
Total Fuel Consumption (onsite plus fuel for macrogrid electricity) (kWh/a)	45,566,102	44,932,424	40,841,017

+++++++++Efficiencies and Fractions+++++++++			
Efficiency of Entire Energy Utilization (Onsite and Purchase)	0.52	0.52	0.58
Natural Gas DER System Efficiency (Elec + Heat)	0.92	0.91	0.91
Natural Gas DER System Efficiency (Federal Regulatory Commission - FERC Definition)	0.61	0.61	0.61
Fraction of Energy Demand Met On-Site	0.11	0.15	0.42
Fraction of Electricity-Only End-Use Met by On-Site Generation	0.1	0.13	0.37
Fraction of Cooling End-Use Met by On-Site Generation	UNDF	UNDF	UNDF
Fraction of Cooling End-Use Met by Absorption Chiller	UNDF	UNDF	UNDF
Fraction of Cooling End-Use Met by Natural Gas	UNDF	UNDF	UNDF
Fraction of Space-Heating End-Use Met by CHP	0.12	0.17	0.46
Fraction of Space-Heating End-Use Met by Natural Gas	0.88	0.83	0.54
Fraction of Water-Heating End-Use Met by CHP	UNDF	UNDF	UNDF
Fraction of Water-Heating End-Use Met by Natural Gas	UNDF	UNDF	UNDF
Fraction of Natural Gas-Only End-Use Met by Natural Gas	UNDF	UNDF	UNDF
+++++++++Model 0ptions+++++++++			
Invest	1	1	1
Sales	0	0	0
StandbyOpt	0	0	0
VaryPrice	0	0	0
CHP	0	0	0
CarbonTax	1	1	1
GasForCool	0	0	0
ForcedInvest	1	1	0
+++++++++Model Parameters+++++++++			
IntRate	0.05	0.05	0.05
Standby	0	0	0
Contrct	0	0	0
turnvar	0	0	0
CTax	0	0	0
MktCRate	0.14	0.14	0.14
macroeff	0.34	0.34	0.34
cooleff	0.13	0.13	0.13
MinEffic	0	0	0
Reliability	0.9	0.9	0.9
AvgCapacity	1,000	1,000	1,000
AbsFraction	0	0	0
m2	0	0	0
b2	0	0	0

m3	0	0	0
b3	0	0	0
BaseCaseCost	20,000,000	20,000,000	20,000,000
MaxPaybackPeriod	20	20	20
+++++++++Installed Units for each available Technology++++++++++++			
Available Technologies are technologies with MaxAnnualHour values greater than 0			
in table GenConstraints in folder Technology Data			
GT-------------05000	2	2	0
GT-------------10000	1	0	0
NG------------00060	3	4	10
+++++++++Reports on an Annual Basis+++++++++			
Loads (All Numbers in kWh)			
1 kWh = 3412.14 BTU			
Annual Electricity-Only Load Demand	10,573,402	10,573,402	10,573,402
Annual Cooling Load Demand	0	0	0
Annual Space Heating Load	12,967,715	12,967,715	12,967,715
Annual Water Heating Load	0	0	0
Annual Natural Gas-Only Heating Load	0	0	0
Annual Total Energy Demand (kWh)	23,541,117	23,541,117	23,541,117
Generation (All Numbers in kWh)			
1 kWh = 3412.14 BTU			
Total Annual Electricity Generation On Site	1,042,695	1422194	3897462
Annual Electricity Generation On-Site to Meet Electricity-Only Load	1,042695	1,422,194	3,897,462
Annual Electricity Generation On-Site to Meet Cooling Load	0	0	0
Annual On-Site Production of Energy (Electricity + Utilized Waste Heat + Natural Gas) (kWh)	2,639,270	3,599,649	9,830,297
Purchase (All Numbers in kWh)			
Annual Electricity Purchase to Meet Electricity-Only Load	9,530,707	9,151,208	6,675,940
Annual Electricity Purchase to Meet Cooling Load	0	0	0
Natural Gas (All Numbers in kWh)			
Annual Natural Gas-Only Load which is met by Natural Gas	0	0	0
Annual Cooling Load which is met by Natural Gas,	0	0	0
Annual Space Heating Load which is met by Natural Gas	11,371,140	10,790,261	7,034,880

Annual Water Heating Load which is met by Natural Gas (kWh)	0	0	0
CHP (All Numbers in kWh)			
Annual Cooling Load which is met by Absorption Chiller	0	0	0
Annual Load of Water Heating which is met by CHP	0	0	0
Annual Load of Space Heating which is met by CHP	1,596,575	2,177,455	5,932,835
Energy Carriers			
Annual DER Natural Gas Purchases (kWh)	3,320,685	4,529,281	12,412,298
Annual NON DER Natural Gas Purchases (kWh)	14,213,926	13,487,826	8,793,600
Annual Net Gas Purchase (kWh)	17,534,611	18,017,106	21,205,898
Annual Total Gas Costs ($)	672,920	691,136	813,706
Annual Net Diesel Purchase (kWh)	0	0	0
Annual Diesel Bill ($)	0	0	0
Emissions			
Annual On-site Carbon Emissions from Natural Gas DER (kg)	163,776	223,384	612,175
Annual On-site Carbon Emissions from Diesel DER (kg)	0	0	0
Annual On-site Carbon Emissions from Natural Gas (kg)	701,031	665,220	433,700
Annual Off-site Carbon Emissions (Macrogrid) (kg)	1,334,299	1,281,169	934,632
Annual Total Carbon Emissions (kg)	2,199,106	2,169,773	1,980,507