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

Final Project Report

September 30, 2008

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Legal Notice

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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.

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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

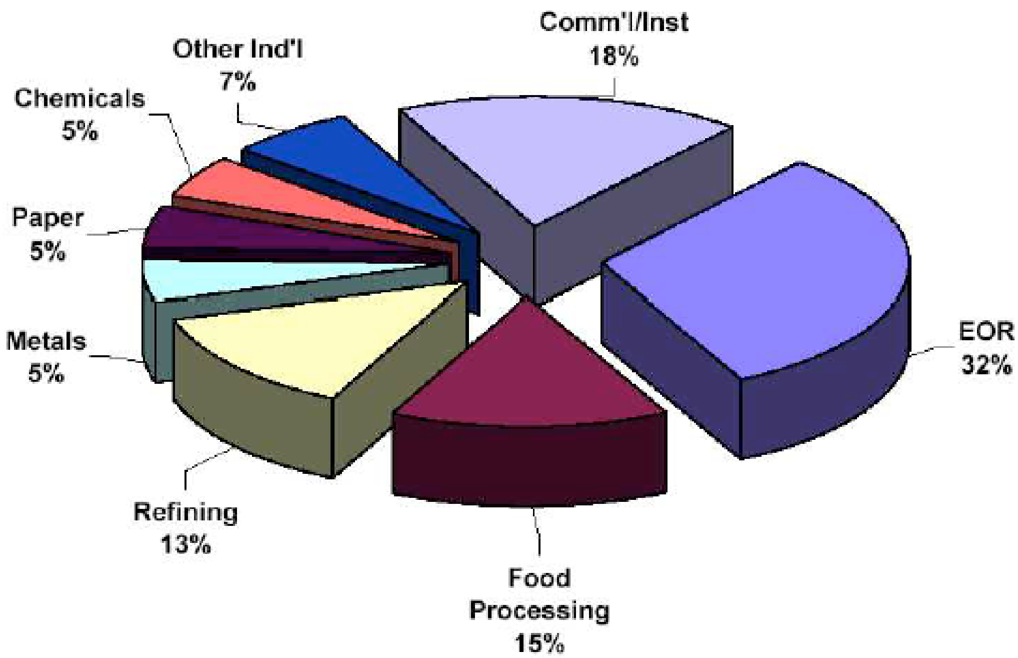
The Pacific region has several hundred CHP installations at present, with most located in California and in a wide range of industrial and commercial applications. The latest version of the Energy and Environmental Analysis Inc. (EEA) database of CHP installations in the state shows a total of 947 sites (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).

<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, 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.

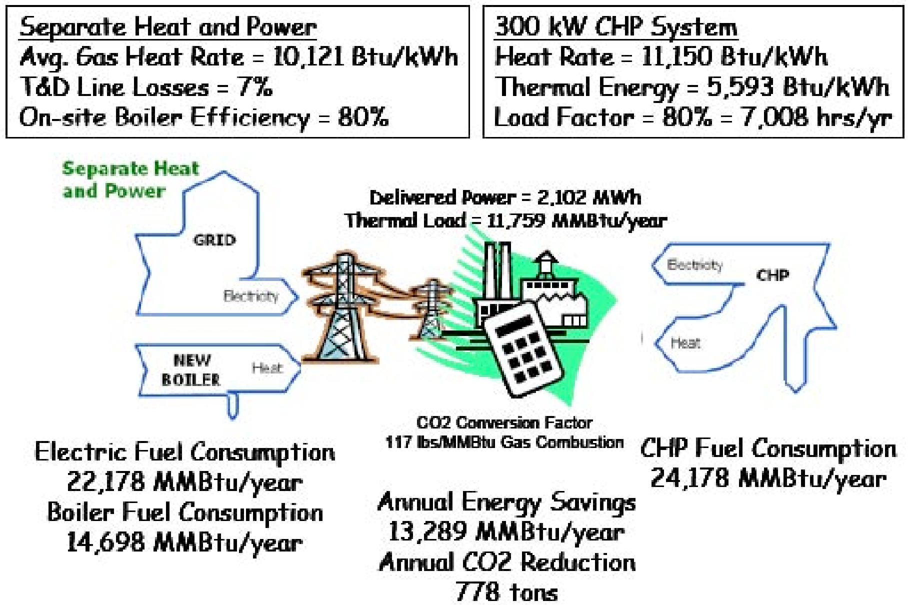


Figure ES-2: Estimate of the Carbon Reduction Benefits from CHP Systems
(Source: EPRI, 2005)

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

<u>Summary of CHP System Financial Assistance Programs</u>

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.

<u>Action Plan for Advancing the CHP Market in California</u>

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).

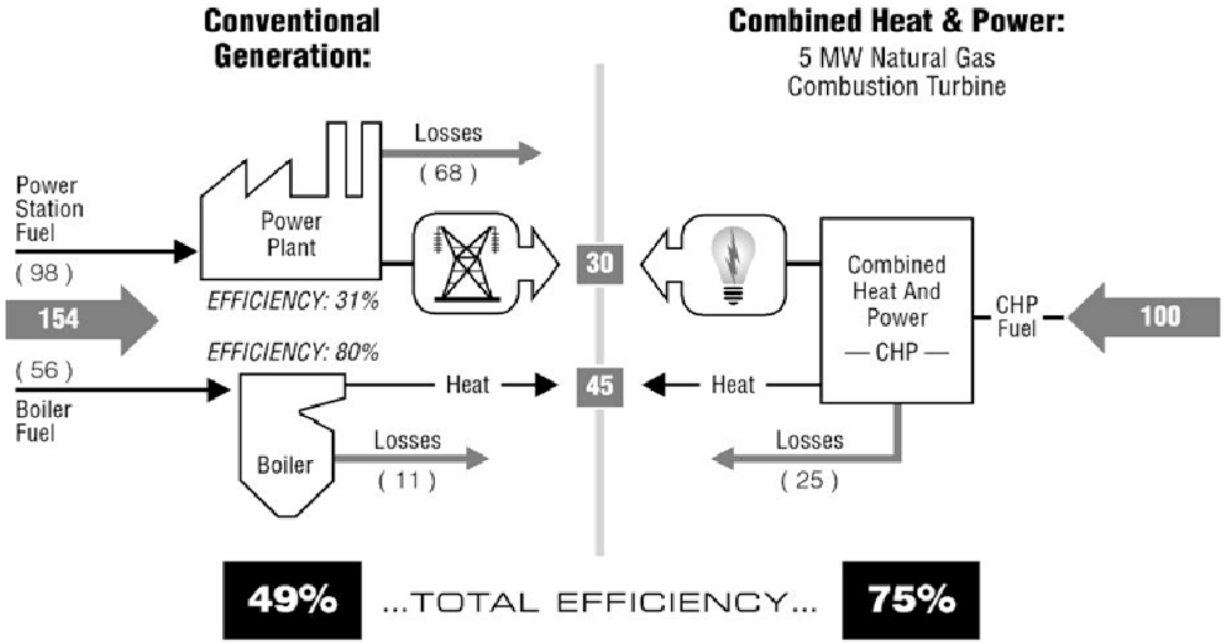
The information presented in this report is intended to provide:

- 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.

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.

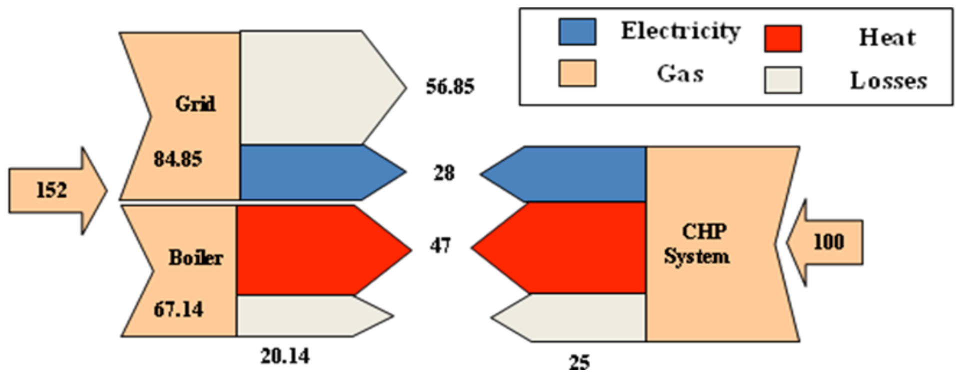
[4] Hereafter, the California Energy Commission is referred to as "the Energy Commission."



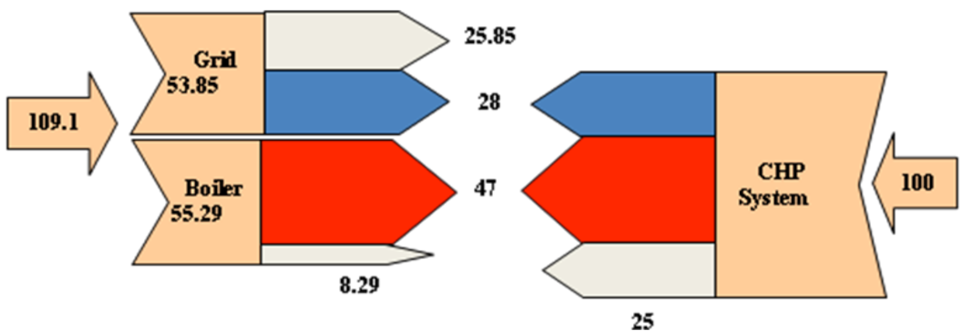
Source: Hedman, 2006

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.

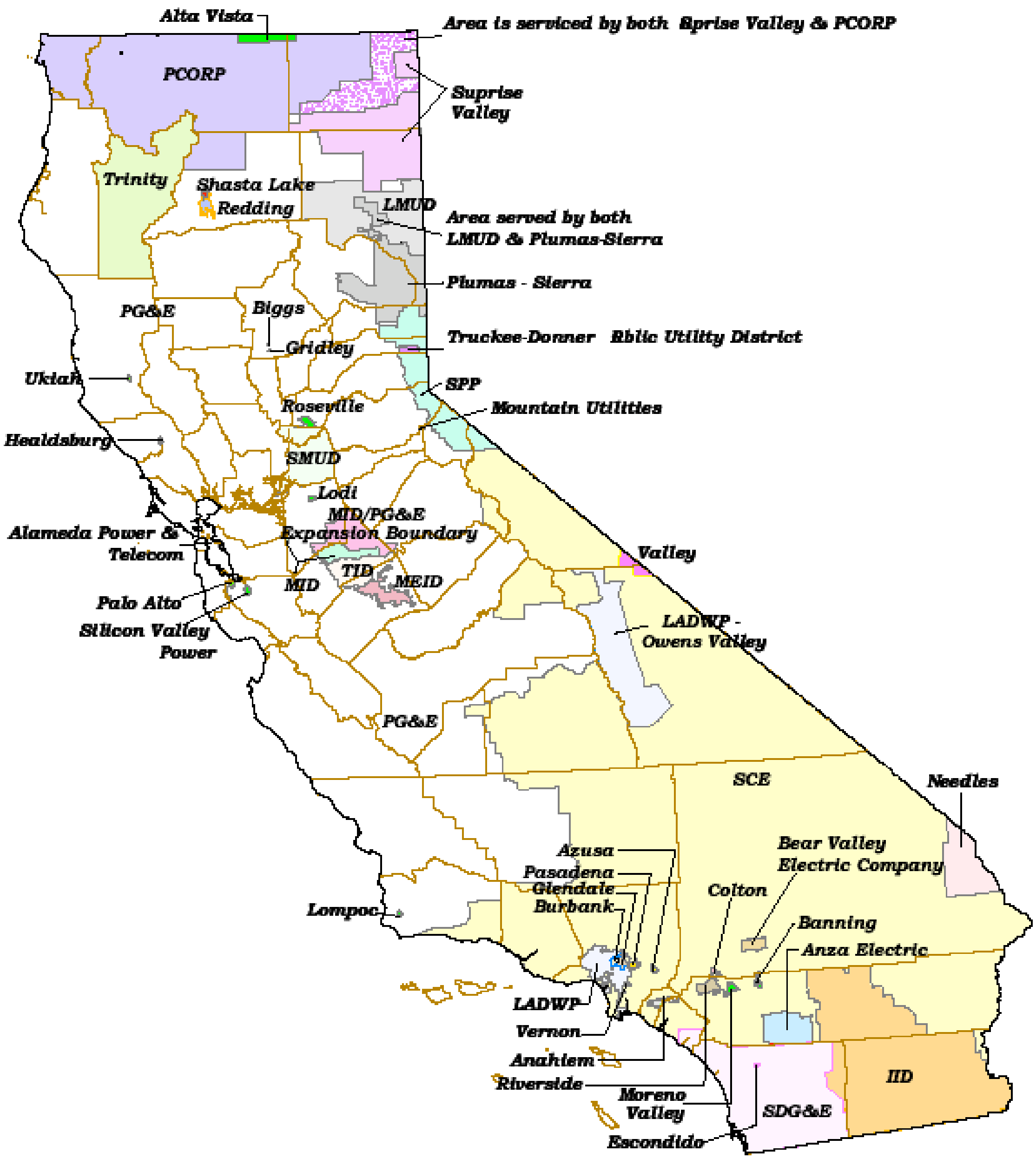


Figure 3: California Electric Utility Service Territories

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).

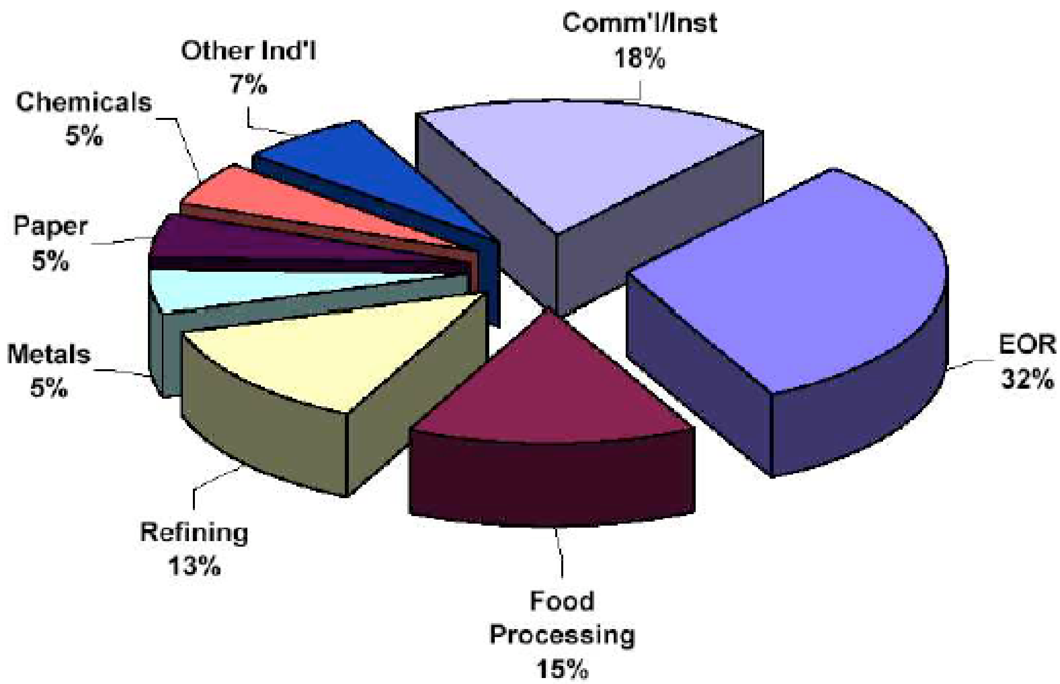
Table 1: Electricity Generating Capacity and CHP Installations in the Pacific Region

	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).

[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).

<u>Grid Access and Interconnection Rules</u>

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

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[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.

Utility Rates, Standby Charges, and Exit Fees

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.

<u>Market Incentives for CHP System Installation</u>

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™ 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.

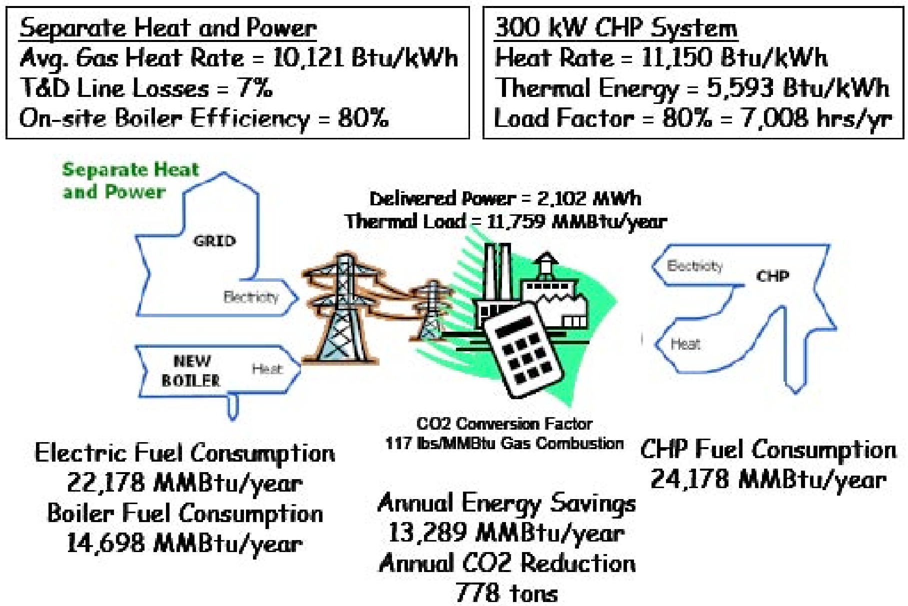

Figure 5: Estimate of the Carbon Reduction Benefits from CHP Systems
(Source: EPRI, 2005)

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.

<u>Assembly Bill 1613: The Waste Heat and Carbon Emissions Reduction Act</u>
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, 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. (T)

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

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