

FINAL STAFF PAPER

A New Generation of Combined Heat and Power: Policy Planning for 2030

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SEPTEMBER 2012

CEC-200-2012-005

ACKNOWLEDGEMENTS

The author would like to thank Linda Kelly and Melissa Jones at the California Energy Commission for their support and guidance during the writing of this paper.

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

ABSTRACT

This staff paper analyzes the state's existing portfolio of combined heat and power plants, how that capacity was reached, and how future policy goals for combined heat and power may be achieved. Existing and projected electricity and natural gas prices; state programs, mandates, and policy goals; and various stakeholder influences coalesce in a collection of complex interactions that influence the viability of combined heat and power. These outcomes range from minimal capacity additions (other than those that would provide the equivalent generation of the existing combined heat and power fleet) to substantial new development to meet the state's goal of 6,500 megawatts additional combined heat and power over the next 20 years. Current state and federal policy will more likely lead to the former, while substantial legislative and industry action will be necessary to reach the latter.

While the report attempts to be comprehensive, not all options may be included, and those that are may not be viable. Political will (or lack thereof) and legal action may derail the best laid plans. From a technical standpoint, there is a substantial thermal load in California that could be met with combined heat and power to reach the state's goal, either by using the generated electricity on-site or exporting it to the grid. The feasibility of meeting the state's combined heat and power goals will depend on addressing the limitations of the technology's characteristics, physical integration issues, and cost parameters.

Keywords: Combined heat and power, cogeneration, CHP, distributed generation

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EXECUTIVE SUMMARY

Background

Combined heat and power (CHP) systems generate on-site electricity and useful thermal energy in a single integrated system. Less fuel is consumed in a typical CHP system than would be required to obtain electricity and thermal energy separately. Since less fuel is consumed, CHP systems offer greenhouse gas (GHG) reduction benefits over the conventional method of obtaining heat from a boiler and power from the electric grid. Additionally, since CHP system energy is consumed on-site, as a form of distributed generation, no energy is lost through transmission, adding to the energy savings.

As a result, well-designed CHP systems are the most energy-efficient and cost-effective form of thermal distributed generation, providing benefits to California residents in the form of 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.

CHP was generally confined to large-scale industrial processes until the enactment of the Public Utilities Regulatory Policy Act of 1978 (PURPA). PURPA made it mandatory for electric utilities to interconnect with all qualifying CHP and small renewable power facilities, to purchase power from these facilities at their “avoided costs,” and to provide supplementary and backup power on a nondiscriminatory basis. Other programs spurred growth in the small-scale CHP sector, including Assembly Bill 1969 (Yee, Chapter 731, Statutes of 2006), Assembly Bill 1613 (Blakeslee, Chapter 713, Statutes of 2007) (AB 1613), and the Self-Generation Incentive Program. The installed capacity at the start of 2012 was 8,815 megawatts (MW) at 1,202 sites.

On October 8, 2010, settling parties, which included CHP facility owners and utilities, submitted the *Qualifying Facility and Combined Heat and Power Program Settlement Agreement* (QF Settlement) for approval to the California Public Utilities Commission (CPUC). This new contracting mechanism, approved by the Federal Energy Regulatory Commission, suspended PURPA for CHP facilities greater than 20 MW and replaced it with a competitively bid solicitation program.¹ On November 23, 2011, the QF Settlement became

¹ In October 2006, FERC issued Order No. 688: “...revising its regulations governing utilities’ obligations to purchase electric energy produced by QFs. Order No. 688 implements PURPA section 210(m), which provides for termination of the requirement that an electric utility enter into power purchase obligations or contracts to purchase electric energy from QFs, if the Commission finds the QFs have nondiscriminatory access to markets.”

In D.07-09-040, the CPUC recognized that it would need to address the impact of the California ISO’s Market Reform and Technology Upgrade on short-run avoided cost and the QF program. The Market

final and nonappealable and achieved three clear goals: (1) resolved all outstanding legal disputes; (2) developed additional power purchase agreement options for CHP qualifying facilities; and (3) established a smooth transition from the existing PURPA program for qualifying facility CHP to a state-administered CHP program designed to achieve California's GHG reduction goals.

The objectives laid out in this new CHP program by the *QF Settlement* are that the utilities will sign 3,000 MW of CHP contracts and reduce emissions from CHP resources by 4.3 million metric tons. This emissions reduction goal corresponds to Assembly Bill 32 (Núñez, Chapter 488, Statutes of 2006) *Scoping Plan's* goal for CHP as it is equivalent to the utilities' portion of the goal based on load served.

In the 2010 Long-Term Procurement Plan proceeding², the QF Settlement MW targets were also approved for procurement activities through 2015.

As part of the California Air Resources Board's implementation of AB 32, a carbon emissions credit market is being established, more commonly known as *cap and trade*. The goal of cap and trade is to have the price of carbon incorporated into the price of energy, both electric and natural gas prices, by 2015. CHP is affected by cap and trade because it shifts emissions from the grid to the facility where the CHP system is located. While it decreases overall emissions compared to the combined use of an on-site boiler and grid electricity, the emissions attributable to the facility increase. Once the price of carbon is fully incorporated into all energy prices, the distinction of where the emissions occur disappears.

In the most recent version of the Self-Generation Incentive Program, conventional CHP technologies were reinstated, although at a much lower level than other technologies, and are eligible for financial incentives for the installation of new qualifying CHP. Also, the biogas incentive was altered so that it acts as an adder for eligible fuel cells and conventional CHP technologies. Fuel cells are still the only CHP-capable technology that can be used in electric-only applications.

The AB 1613 investor-owned utility contracts for projects no more than 20 MW and no more than 5 megawatts were approved by the CPUC on December 15, 2011. Contracts for projects no more than 500 kilowatts were submitted in April 2012 and are under review at the CPUC. The applications have signaled a welcomed reception from CHP developers for the AB 1613 feed-in tariff, but to date, none have yet been able to capitalize on its intent.

Reform and Technology Upgrade established nondiscriminatory access to markets that allowed the utilities to move towards reforming the QF program in California.

Provided the *QF Settlement* provides a competitive market for CHP resources according to FERC, the utilities are no longer required to offer contracts under PURPA's must take obligation program to facilities greater than 20 MW.

2 CPUC Rulemaking 10-05-006.

Purpose

This paper documents the history and articulates the barriers CHP faces now and in the coming decade. It explains the issues surrounding CHP policy and procedures that affect CHP development and examines its place in California's resource portfolio. Governor Edmund G. Brown Jr. set forth a CHP goal for the state. This paper lays out a path toward that goal by detailing recent progress in the CHP market and proposing potential solutions to address the issues raised herein.

Objectives

The objectives analyze the details of CHP policy, programs, and plans to reach actionable conclusions that, if implemented, would help meet the state's policy goals.

Financing and Regulatory Barriers

As the electric grid changes, the role for CHP will have to change to meet evolving system needs. Electric system planning used to focus on how to cost-effectively meet demand using base load technologies and expensive gas-fired peaking plants to schedule around the other available resources. State policy has added numerous other conditions to the cost minimization constraint, most prominently the Renewables Portfolio Standard. This additional focus, maximizing energy from renewable resources, has shifted the way other resources are valued. While CHP is still an important resource to reduce demand and provide efficient use of natural gas, waste heat, and waste gas resources, its value to grid operators has changed.

In response, the old way of thinking about how to design a CHP system needs to change, and along with it, the processes that dictate how CHP operates. This will require developing new creative business models, flexible contracts, and requests for offers that recognize the contribution that CHP resources can make to improve system stability and reliability. Without these changes, CHP projects will have limited economic incentives to participate and be integrated into the dynamic grid of the future. However, it does not necessarily follow that just because a market for energy, capacity, and other services develops that CHP projects will come to fruition. Some things do not change; cost certainty through long-term contracts is still the way projects get built.

Departing load charges, cap-and-trade costs, the lack of an export market for excess generation, and interconnection costs are just a few of the uncertainties that make project financing more difficult. Finding private sector financial backing for projects that face so much uncertainty is a struggle for many developers. The state's inconsistent backing of CHP, illustrated by the possible financial burden of cap and trade, makes investors wary. This risk, perceived or real, increases the cost of financing projects. Providing financial assistance to clean, efficient CHP projects in the form of project screening for technical and financial feasibility as well as education and outreach about state programs, such as the Self-Generation Incentive Program and AB 1613, will help decrease this risk. However, reducing risk is the goal, and showing strong state support for CHP by reducing existing barriers will have more tangible results for CHP development than creating new incentive programs.

New business models alone, however, will not address the continuing regulatory barriers that discourage the development of CHP in California. These barriers were identified in the 2012 *Integrated Energy Policy Report (IEPR)* CHP Workshop:³

- Cap-and-trade provisions
- Demand charges, standby charges, and departing load charges
- Interconnection and metering costs and requirements
- Lack of net-energy metering eligibility
- Lack of a long-term (beyond 2015) CHP goal in long-term procurement plans

In its current form, a cap-and-trade system is a disincentive to invest in clean, efficient CHP. The outcome of pending legislation will determine who will be responsible for correcting this regulatory oversight. Two courses of action are possible to restore CHP's natural advantage gained through its net efficiency over separate electric and thermal generation: 1) the agency that is responsible for allocating collected funds, whether the CPUC or some other state board, should provide compensation to CHP during the cap-and-trade implementation period; or 2) the California Air Resources Board should revisit the cap-and-trade provisions that apply to CHP.

The accounting method used by the ARB in its *Scoping Plan*, as identified in ICF's *Combined Heat and Power: Policy Analysis and 2011-2030 Market Assessment*⁴, leads to the conclusion that exported electricity from a CHP project reduces more greenhouse gases than electricity used on-site. The state's preference for DG resources, whose electricity is consumed on-site or locally, runs counter to the adopted method. In addition, utilities have moved away from high-export, PURPA-style projects, the very projects that, using this method, produce the greatest greenhouse gas reductions. This is a problem CHP facilities will have to deal with unless CHP electricity consumed on-site is taken into account when calculating the total energy generated when calculating the RPS. This is what happens when electricity is exported; it becomes part of the utility's RPS calculation. For the most efficient, least polluting result, CHP should be incorporated into the RPS calculation, allowing all electricity generated, on-site or exported, to be compared to the utility's marginal, or least efficient, generator. If this change does not occur, CHP will be forced to compete with grid electricity that is ever increasing in its percentage of renewable resources. This is a

3 2012 IEPR Lead Commissioner Workshop on Combined Heat and Power in California, February 16, 2012. http://energy.ca.gov/2012_energypolicy/documents/2012-02-16_workshop/2012-02-16_Transcript.pdf.

4 Hedman, Bruce, Ken Darrow, Eric Wong, Anne Hampson. ICF International, Inc. *Combined Heat and Power: 2011-2030 Market Assessment*. June 2012. California Energy Commission. CEC-200-2012-002-REV.

competition that CHP cannot win. CHP may be cleaner than the utility's marginal generator but may not be to the grid's entire resource mix.

It has been nearly a decade since demand, standby, and departing load charges were established. Since then, actions have been taken that allow certain technologies or size of technologies be exempt from these charges. CHP stakeholders believe that the current regulatory environment will not lead to the desired results as stated by the state's policy goals in regards to CHP. The charges should balance costs incurred serving CHP generators while taking into account all the benefits those generators provide and the state's policy goals.

Interconnection is a long, and often costly, process. While this is difficult for new facilities, it is even more complicated for facilities that are expanding their operations behind a common point of coupling. Any expansion requires a full interconnection study, a two-year process. The difficulty is only increased when dealing with existing contracts. Interconnecting at an alternate junction is not always an option, and when it is, it typically costs more as it requires more extensive equipment upgrades. As the state looks toward increasing the size of its CHP fleet and once-through cooling plant retirements, the number of these projects will only increase. As such, interconnection requirements for generation expansion at existing facilities should be eased.

Meters are necessary, but also an additional financial burden on developers, and may prove redundant as more of them are required to meet the requests of the utilities, the California Independent System Operator, and state regulatory agencies. Looking at ways to standardize metering requirements and reduce their costs, both to the technology and to the developer, should be a policy priority.

Conventional CHP technologies are ineligible for the net-energy metering program. Arguments that point at its generation profile as reason for its exclusion ignore the fact that fuel cells have a similar profile, and wind generation occurs primarily at night. Both of these technologies are eligible for the program. Net metering should maintain the appropriate price signals when dynamic pricing becomes a reality, but in the meantime net-energy metering eligibility should be technology-neutral. If the CPUC wishes to consider the time-dependent aspect of electricity generation for net-energy metering-sized projects, it should do so without a technology bias.

Actionable Items

- The CPUC should allow a larger percentage of new utility-owned or co-owned CHP generation to count toward the utilities' GHG reduction goals. The CPUC, with aid from the utilities and CHP advocates, should create a legal framework that allows flexibility in request-for-offer proposals and power purchase agreements.
- Either the CPUC, through the use of cap-and-trade funds, or the ARB, through the allocation of emission allowances, should restore the natural advantage CHP has through its efficient use of fuel so it is not disadvantaged by the implementation of cap and trade.

- The Legislature should amend the Renewables Portfolio Standard program to either exempt electricity purchased from CHP resources that are more efficient than the local utility's marginal generator from the calculation of total retail sales, or include all electricity generated from CHP resources in a utility's territory in the calculation of total retail sales.
- The CPUC should revisit demand charges, standby charges, and departing load charges as they apply to CHP resources.
- The various agencies should evaluate the interconnection requirements in their jurisdiction (Rule 21, the Wholesale Distribution Access Tariff, and the Generator Interconnection Procedures) to ease the process of interconnection at facilities that expand their generation capabilities.
- The Energy Commission should provide analysis of the various metering requirements across programs and agencies to consolidate the requirements.
- The Electric Program Investment Charge program should identify technical research necessary to reduce costs and develop uniform meter standards for all state and federal jurisdictions including the Self-Generation Incentive Program, utility telemetry requirements at the distribution level, and California Independent System Operator telemetry requirements at the transmission level.
- The state regulatory agencies should implement the recommendations that result from the metering requirement analysis and research and revisit the rules that govern net-energy metering eligibility.
- The Energy Commission should explore ways to provide financial assistance to clean, efficient CHP projects.

Long-Term Planning

The success of the Renewables Portfolio Standard is seen as a viable pathway for CHP developers to achieve the state's CHP goals. Developers and CHP manufacturers saw the barriers to solar resource development fall away once the RPS was put in place. Many of the charges that other generators, including CHP, have to pay, such as standby charges and departing load charges, are not charged to renewable resources. In addition, renewable energy projects have numerous additional incentives ranging from waiving interconnection study fees and metering equipment cost subsidies to a higher-paying feed-in tariff and net-energy metering eligibility. A portfolio standard may not be necessary in itself to encourage CHP, but it has removed barriers, created incentives, and produced tangible results for renewable resources.

Utilities and others have indicated they do not support a mandate or portfolio standard for CHP. If a portfolio standard is considered, a number of additional issues should be addressed. CHP needs to be located at thermal loads, and these are not evenly distributed among the utilities. Since these facilities are located at private facilities, they require more collaboration with owners; utilities cannot simply go out and build these facilities on their

own. Additional request for offers could be held in a similar fashion to the *QF Settlement*, with caveats that development would best meet both system and host-site needs.

The dichotomy between what the utilities want and what developers need to meet the state's CHP goals is most clearly seen at the CPUC where various parties advocate for how much CHP development should be included in the utilities' long-term procurement plans. The utilities have presented very low numbers, including zero development after 2015. While zero, as the CPUC has stated⁵, is less reasonable, an appropriate target for development after 2015 is still open to debate and will most likely be a focus of the 2014 proceeding. For large-scale CHP, maintaining a placeholder for future CHP development in the long-term procurement plans is essential. If CHP is seen as the residual resource after other resource procurement is planned, efficient CHP will be undervalued and its procurement argued against for lack of need. In light of the effectiveness of the renewable portfolio standard, the importance of a long-term goal in the utilities' long-term procurement plans, and the lack of serious targets being presented by the utilities in those procurement plans, a CHP portfolio standard may be the only viable option if barriers to CHP development remain, and the state is unable to reach its goals.

Actionable Items

- The Energy Commission should reach out and educate both the private sector and the public about the opportunities and benefits provided by CHP to encourage participation and support in existing programs for CHP.
- The Energy Commission and CPUC should continue to track, analyze, and report to the Governor and legislature on the progress and success of the *QF Settlement*, AB 1613, and other state programs designed to encourage new CHP.
- The Energy Commission should revisit and update the CHP technical assessment in late 2013 or early 2014 to provide information on CHP development for the 2014 long-term procurement planning proceeding. This will also provide an opportunity to assess the impacts of cap and trade on CHP before its full implementation in 2015.
- Depending on the progress towards meeting the state's CHP capacity target and the recommendations listed here, the state should consider a CHP portfolio standard.

Conclusion

From a technical standpoint, there is substantial thermal load in California that could be met with CHP to reach the state's goal, either by using the generated electricity on-site or exporting it to the grid. The feasibility of meeting the state's CHP goals will depend on addressing the limitations of the technology's characteristics, integration issues, regulatory treatment, and financial risk.

⁵ CPUC Decision 12-01-033, pp 32-33.

CHAPTER 1:

Introduction

Combined heat and power (CHP) systems, also referred to as cogeneration, generate on-site electricity and useful thermal energy in a single integrated system. Less fuel is consumed in a typical CHP system than would be required to obtain electricity and thermal energy separately. Since less fuel is consumed, CHP systems offer greenhouse gas (GHG) reduction benefits over the conventional method of obtaining heat from a boiler and power from the electric grid. Additionally, since CHP system energy is consumed on-site as a form of distributed generation (DG), no energy is lost through transmission, adding to the energy savings.

As a result, well-designed CHP systems are the most energy-efficient and cost-effective form of thermal DG, providing benefits to California residents in the form of 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.

Widespread development of efficient CHP systems will help avoid the need for new power plants or expansion of existing plants. Electricity generation at centralized power plants is inherently inefficient, converting less than 50 percent of a fuel's energy into electricity with the balance lost as waste heat. By producing both electricity and usable heat, appropriately designed CHP systems may convert as much as 90 percent of a fuel's energy into usable energy, resulting in cost savings and significant carbon emission reductions.

DG, including CHP, has been recognized and encouraged by the California Energy Commission since the 1990s as a valuable alternative to developing new fossil-fueled, central-station power plants to meet California's growing energy demands. DG and CHP are also key elements of California's "loading order," following energy efficiency, demand response, and renewable energy.⁶

Two predominant state policies have set the goals for CHP development in California. One is Assembly Bill 32 (Núñez, Chapter 488, Statutes of 2006) (AB 32), the *Global Warming Solutions Act*.⁷ Under this Act, the California Air Resources Board (ARB) prepared an *AB 32 Scoping Plan*⁸ that includes a reduction goal of 6.7 million metric tons (MMT) of carbon

6 Bender, Sylvia, Pam Doughman, David Hungerford, Suzanne Korosec, et.al. *Implementing California's Loading Order for Electricity Resources*. July 2005. California Energy Commission. CEC-400-2005-043.

7 <http://www.arb.ca.gov/cc/ab32/ab32.htm>.

8 <http://www.arb.ca.gov/cc/scopingplan/scopingplan.htm>.

dioxide (CO₂) from CHP resources. The other is Governor Brown's Clean Energy Jobs Plan.⁹ This plan calls for 6,500 megawatts (MW) of new CHP capacity by 2030.

To reach these goals California has established an incentive program, approved feed-in tariffs, amended interconnection procedures numerous times, and a new procurement process for the state's investor-owned utilities (IOUs). Many of these changes are in their early stages, and their effect has yet to be seen in the state's installed CHP capacity tally.

Currently there are 8,515 MW of installed CHP capacity in California, with the energy generated split across 30 percent used on site and roughly 70 percent exported to the grid.

This level of CHP capacity places California second nationally. Texas has the greatest installed capacity with 17,319 MW, while New York is third with 5,559 MW.¹⁰

This paper will raise and attempt to answer numerous questions that lead up to the penultimate question: How does California reach its MW and greenhouse gas (GHG) reduction goals? It will start with examining the path California took and what programs were used to get to the installed capacity that exists today. It will highlight lessons learned and identify effective strategies that were used. Looking forward, staff will use ICF's *Combined Heat and Power: Policy Analysis and 2011-2030 Market Assessment*¹¹ (2011 ICF Market Assessment) and stakeholder input from the February 16, 2012 *Integrated Energy Policy Report: Lead Commissioner Workshop on Combined Heat and Power in California* (2012 IEPR CHP Workshop) to analyze state programs, regulatory barriers, and policy scenarios. These will provide a basis from which staff will make policy recommendations to stimulate CHP development to reach the Governor's goal, and note the regulatory barriers that may prevent these actions from having their desired estimated impact.

The chapters of this paper focus on the regulatory path CHP has traversed; existing CHP programs and the implications of regulatory developments and policy changes; the findings of the Energy Commission sponsored study, *2011 ICF Market Assessment*; the issues raised in the 2011 IEPR CHP Workshop or submitted in written comments; and recommendations and actions to move toward the state's CHP policy goals.

⁹ http://gov.ca.gov/docs/Clean_Energy_Plan.pdf.

¹⁰ <http://www.eea-inc.com/chpdata/index.html>.

¹¹ Hedman, Bruce, Ken Darrow, Eric Wong, Anne Hampson. ICF International, Inc. *Combined Heat and Power: 2011-2030 Market Assessment*. June 2012. California Energy Commission. CEC-200-2012-002-REV.

CHAPTER 2:

History

The history of CHP started out in a single direction guided by regulation at the federal level. Partial deregulation in the late 1990s had repercussions that are still being acted out today. Along the way various incentive programs and feed-in tariffs were established, and interconnection procedures and contractual arrangements were changed. This chapter will trace these twists and turns in the regulatory path of CHP.

Interconnection: Public Utilities Regulatory Policy Act, Rule 21, Generator Interconnection Procedure and Wholesale Distribution Access Tariffs

From the early days of electricity production, certain energy-intensive industries such as pulp and paper mills, chemical plants, and oil refineries generated their own steam and power onsite with large CHP systems. CHP was generally confined to these large-scale industrial processes until the enactment of the Public Utilities Regulatory Policy Act of 1978 (PURPA). PURPA made it mandatory for electric utilities to interconnect with all qualifying CHP and small renewable power facilities, to purchase power from these facilities at their “avoided costs,”¹² and to provide supplementary and backup power on a nondiscriminatory basis. During the decade immediately following the passage of PURPA, CHP capacity in the United States began growing at an annual rate of 6.3 percent. During the 1990s, average growth remained above 5 percent but was mostly due to a large number of installations early in the decade. Growth slowed considerably by the end of the decade.

The passage of PURPA dramatically increased the growth of CHP in California. Before its passage, there were only nine cogeneration units operating in the state. Over the next 10 years, more than 380 additional cogeneration plants were built. The decade from 1988 to 1997 added more than 270 more units. Annual growth in cogeneration capacity went from less than 1 percent in the 1970s to 27 percent in the 1980s.

This growth was aided by the ease of interconnection. Rule 21 is a set of interconnection standards that was originally used to interconnect PURPA qualifying facilities (QFs)¹³ and

¹² The cost the utility would have incurred had it supplied the power itself or obtained it from another source.

¹³ QFs are small power production facilities generating 80 MW or less whose primary energy source is renewable (hydro, wind, solar), biomass waste, or geothermal, or cogeneration facilities that produce electricity and another form of useful energy (such as heat or steam) in a way that is more efficient than the separate production of both forms of energy.

other nonutility-owned generation. The standards were neutral as to export¹⁴ and required a study of each facility, and the facility could interconnect to either the transmission or the distribution system. However, Rule 21 was still a complex process whose tariff language differed between the three investor-owned utilities (IOUs) and lacked specifics such as timelines or costs. As a result, Rule 21 was used by large, predominantly exporting QFs.

By the 1990s, the CHP growth rate had slowed to just over 4 percent. In 1998, after nearly 16 years of double-digit plant additions, only 1 cogeneration plant was added. At that time, there were nearly 6,500 MW of installed CHP capacity in California.

On October 21, 1999, the California Public Utilities Commission (CPUC) issued an order instituting a new rulemaking (R.99-10-025) to address, among other issues, interconnection standards. The following month, the Energy Commission issued an Order Instituting Investigation¹⁵ to identify barriers to developing DG technologies inherent in utility interconnection rules and air quality management district rules. A series of recommended changes to the rules of the CPUC, publicly owned utilities, and air quality management districts resulted. One of the recommendations from the investigation was to develop a statewide set of specific standard interconnection, operating, and metering requirements for distributed energy resources. The Energy Commission led a working group consisting of representatives from the CPUC, the Energy Commission, and the state's electric utilities to rewrite Rule 21 to implement this recommendation.

On December 21, 2000, CPUC Decision 00-12-037 approved in its entirety the Rule 21 language adopted by the working group. With this adoption, Pacific Gas and Electric (PG&E), San Diego Gas & Electric (SDG&E), and Southern California Edison (SCE) replaced former Rule 21 with the approved Model Tariff, Interconnection Application Form, and Interconnection Agreement. This revised version of Rule 21 standardized the language and procedures across the three IOUs and specified timelines and applicant costs for system impact studies.

Spurred on by low gas prices in the early 2000s, as well as the revised Rule 21 and the newly created Self-Generation Incentive Program,¹⁶ CHP development grew to the state's high water mark of 9,130 MW at 776 sites in 2005.

On July 23, 2003, the Federal Energy Regulatory Commission (FERC) issued Order No. 2003, amending its regulations under the Federal Power Act to require electric utilities to revise their open access transmission tariffs containing standard generator interconnection procedures for generators greater than 20 MW in capacity.¹⁷ This was followed by another

¹⁴ Electricity that is not used on-site and fed into the electric grid.

¹⁵ Docket 99-DIST-Gen(2), Order Instituting Investigation, Order No.99-1103-11.

¹⁶ <http://www.cpuc.ca.gov/PUC/energy/DistGen/sgip/>.

¹⁷ FERC Order No. 2003.

FERC Order No. 2006, on May 12, 2005.¹⁸ This order amended its regulations under the Federal Power Act to require electric utilities to amend their open access tariffs to include standard generator interconnection procedures and agreements for generators with a capacity no more than 20 MW.

These two FERC orders established the California Independent System Operator's (California ISO) Small and Large Generator Interconnection Procedures as well as individual utility tariffs. The California ISO is responsible for interconnecting generators to the transmission system while the individual utilities are responsible for interconnecting generators to their respective distribution systems, all of which are FERC-jurisdictional. FERC's standards for Small Generator Interconnection Procedures and its Small Generator Interconnection Agreement would evolve into individual Wholesale Distribution Access Tariffs (WDATs) for each of the three California IOUs. All of these tariff changes were implemented, filed, and approved in the same year they were issued.

On May 15, 2008, the California ISO filed to implement Generator Interconnection Procedures (GIP) reform, which FERC granted. On October 19, 2010, the California ISO filed tariff language with FERC for a new GIP that combined the Small GIP and the Large GIP into annual cluster studies for groups of electrically related projects. FERC approved the GIP, effective as of December 19, 2010.

PG&E and SCE immediately initiated stakeholder processes to develop amendments to their WDATs to implement an equivalent cluster study process to ensure continued coordination with the California ISO's GIP. Both these requests were approved by FERC. SDG&E did not revise its WDAT. While most of the uniformity was maintained, small differences surfaced among the utilities.

The second half of the decade saw additional development of small-scale CHP but a decline in the overall installed capacity. Part of this decline was spurred by high natural gas prices early in the decade, making the cost of fuel too high relative to the price of utility electricity. By 2009, the installed capacity had dropped to 8,829 MW at 1,183 sites. Despite the significant drop in natural gas prices, this trend continues today as the installed capacity at the start of 2012 was 8,815 MW at 1,202 sites.

On April 29, 2011, the CPUC held a workshop to evaluate the status of Rule 21. This included identifying the technical issues affecting interconnection, discussion of the working group's guiding principles, and establishing need, scope, and rough priorities of the most urgent interconnection issues for reform. In August, the CPUC used the findings of this workshop to launch a settlement process to once again reform Rule 21.

On March 16, 2012, 14 parties to the Distribution System Interconnection Settlement Process filed a settlement in CPUC Rulemaking 11-09-011. This settlement achieves the goal of crafting transparent rules that provide a clear, predictable path to interconnection for DG

¹⁸ FERC Order No. 2006.

while maintaining the safety and reliability of the electric grid. Following are key provisions highlighting the proposed reforms under CPUC consideration:

- Introduction of a “Fast Track” process designed to build on Rule 21’s successful screening process for nonexport and net-energy-metering customers, expanding Fast Track eligibility to exporting generating facilities up to certain size limits.
- Introduction of a national best practice for DG penetration levels, under which combined interconnected generating capacity can be equal to 100 percent of minimum load on a distribution line section.
- Specific, transparent time frames for each analysis track, ranging from simplified Fast Track review to the detailed Independent Study Process.
- New rules under which DG developers obtain and retain queue position are set out, including publication of an integrated queue by each IOU for exporting generating facility applicants at the distribution level.
- A “Pre-Application Report” as a first look at the potential point of interconnection, to assist DG developers with early identification of potential technical benefits or challenges of siting decisions.
- Introduction of new dispute resolution mechanisms designed to respond to developers’ needs, including a utility ombudsman authorized to address certain interconnection-related disputes, and expedited handling of timeline-related disputes by the CPUC’s Alternative Dispute Resolution Program.

Incentives: Self-Generation Incentive Program

In the early 2000s, with electricity prices at an all-time high and rolling blackouts becoming a regular occurrence, a bill set out to reduce peak load by encouraging the development of small DG CHP systems. Assembly Bill 970 (Ducheny, Chapter 329, Statutes of 2000) was implemented by the CPUC in Decision 01-03-073, creating the Self-Generation Incentive Program (SGIP).¹⁹ The program, administered by the three IOUs, provides incentives for the installation of new qualifying electric generation equipment that meets all or a portion of the electric needs of a customer’s facility. Technologies initially eligible for the SGIP included CHP technologies (microturbines, internal combustion engines and small gas turbines), renewable technologies (photovoltaics, wind turbines), and fuel cells, as shown in **Table 1**.

¹⁹ Regional Economic Research submitted to SCE. *First Year Evaluation Report - Self-Generation Incentive Program*. June 2002.

Table 1: Summary of Original Self-Generation Incentive Program Incentive Levels

Incentive Category	Maximum Incentive Offered (\$/watt)	Maximum Incentive as a % of Eligible Project Cost	Minimum System Size (kW)	Maximum System Size Incentivized (kW)	Eligible Generation Technologies
Level 1	\$4.50	50%	30	1,000	Photovoltaics, Fuel Cells, ²⁰ Wind Turbines
Level 2	\$2.50	40%	None	1,000	Fuel Cells ²¹
Level 3	\$1.00	30%	None	1,000	Microturbines, ²² Internal Combustion Engines and small gas turbines ²³

Source: CPUC, Decision 01-03-073.

Assembly Bill 1685 (Leno, Chapter 894, Statutes of 2003) extended the initial SGIP program past its original 2004 end date through 2007. During this time significant modifications were made; in particular, photovoltaic technologies were removed at the start of 2007 due to the enactment of the California Solar Initiative. In addition, Assembly Bill 2778 (Lieber, Chapter 617, Statutes of 2006) extended the program through 2012 but limited project eligibility to “ultra-clean and low emission distributed generation” technologies. These technologies were defined as fuel cells and wind DG technologies that met or exceeded emission standards required under the DG certification program adopted by the ARB. AB 2778 also set minimum system efficiency eligibility for SGIP projects based on electrical and process heat efficiencies and taking into account nitrogen oxide emissions. Starting in 2008, technologies including microturbines, internal combustion engines, and small gas turbines, no matter their efficiency or emission levels, were no longer eligible for the SGIP.

Once again, in 2009, another bill set out to alter the SGIP. Senate Bill 412 (Kehoe, Chapter 182, Statutes of 2009) modified the program to focus on GHG reductions. It also directed the CPUC, in consultation with the ARB, to identify distributed energy resources that will contribute to GHG reduction goals and to set appropriate incentive levels to encourage their adoption. The bill’s aim was to include the missed opportunities to support clean distributed energy technologies that reduce greenhouse gas emissions, such as biogas-

²⁰ Operating on renewable fuel.

²¹ Operating on nonrenewable fuel.

²² Using sufficient waste heat recovery and meeting reliability criteria.

²³ Both using sufficient waste heat recovery and meeting reliability criteria.

fueled CHP generation, efficient natural gas-fueled CHP, and peak-load reduction technologies such as energy storage. The bill allowed the CPUC to determine SGIP technology eligibility and extended the program's expiration by one year.

The CPUC rulemaking to reform the SGIP took longer than expected, and, during that time, fuel cells and wind projects were the only eligible technologies that could apply to the program. To preserve the remaining funds while the reform took place, the program was put on hold starting in January 1, 2011. A proposed decision was reached in September 2011, and the program began accepting new applications under the remaining 2011 budget before the end of the calendar year.

The current incentive structure provides half the funds up front, and the other half over the next five years as long as the facility meets its performance criteria. The maximum project size has also changed over the years and with this latest reform has been removed. The SGIP provides funds only for the first 3 MW of a project and reduces stepwise from 100 percent to 50 percent to 25 percent for each MW. Current eligible technologies and their various funding levels are in **Table 2**.²⁴

Table 2: Summary of Self-Generation Incentive Program Funding Levels for 2011 and 2012

Technology Type	Incentive (\$/W)
Renewable and Waste Heat Capture	
Wind Turbine	\$1.25
Bottoming-Cycle CHP	\$1.25
Pressure Reduction Turbine	\$1.25
Conventional Fuel-Based CHP	
Internal Combustion Engine - CHP	\$0.50
Microturbine - CHP	\$0.50
Gas Turbine - CHP	\$0.50
Emerging Technologies	
Advanced Energy Storage ²⁵	\$2.00
Biogas ²⁶	\$2.00
Fuel Cell - CHP or Electric Only	\$2.25

Source: CPUC, Decision 11-09-015.

Development under the SGIP includes 337 projects with an installed capacity of 191 MW. However, by the end of 2011, only 171 MW of that capacity remained.

²⁴ CPUC, Decision 11-09-015. September 8, 2011.

²⁵ Stand-alone or paired with solar photovoltaics or any otherwise-eligible SGIP technology.

²⁶ The biogas incentive is an adder that may be used along with fuel cells or any conventional CHP technology.

Due to the delay in implementation and popularity of the SGIP, the Legislature passed another bill altering the program, Assembly Bill 1150 (Pérez, Chapter 310, Statutes of 2011). This bill extended the collection and allocation of funds for an additional three years. Funds for the SGIP will be collected through 2014, which will fund the program through 2016.

AB 1969: Renewable Generation Feed-In Tariff

Assembly Bill 1969 (Yee, Chapter 731, Statutes of 2006) authorized the creation of tariffs and standard contracts for purchasing eligible renewable generation from public water and wastewater facilities no more than 1.5 MW in capacity. The CPUC implemented this bill with the adoption of Decision 07-07-027, effective February 14, 2008. This tariff was amended by Senate Bill 32 (Negrete McLeod, Chapter 328, Statutes of 2009), which also authorized additional tariffs beyond those required for AB 1969 to customers other than the public water and wastewater customers in PG&E, SCE, and SDG&E service territories and increased the eligible project size to 3 MW and the total program cap to 750 MW statewide. At the end of 2011, installed capacity under this program was 38.5 MW, of which 17.1 MW is attributed to 16 CHP projects.

AB 1613: The Waste Heat and Carbon Emissions Reduction Act

In 2005, the Energy Commission sponsored a CHP study that resulted in the report *Assessment of CHP Market and Policy Options for Increased Penetration*.²⁷ Among the report's findings, it identified the largest underdeveloped area for CHP as mid-sized facilities starting at 1 to 5 MW and going up to 20 MW. In 2007, the Waste Heat and Carbon Emissions Reduction Act was passed to take advantage of this finding. The Waste Heat and Carbon Emissions Reduction Act, known better as Assembly Bill 1613 (Blakeslee, Chapter 713, Statutes of 2007), and amended by Assembly Bill 2791 (Blakeslee, Chapter 253, Statutes of 2008), directed the Energy Commission to adopt by January 1, 2010, guidelines establishing technical criteria for eligibility of CHP systems, and the CPUC and publicly owned utilities to develop programs for certified systems. The CPUC was also directed to establish a standard tariff for selling electricity to electrical corporations for delivery to the electrical grid, and a "pay as you save" pilot program requiring electrical corporations to finance the installation of qualifying CHP systems by nonprofit and government entities.

The Energy Commission adopted final guidelines at a business meeting on January 27, 2010 (modified guidelines adopted April 7, 2010), meeting the efficiency, emissions, and performance criteria of the act provided in Section 2843:

²⁷ Electric Power Research Institute. *Assessment of CHP Market and Policy Options for Increased Penetration*. April 2005. CEC-500-2005-060-D.

- Designed to reduce waste energy
- Minimum efficiency of 60 percent
- Nitrogen oxides emissions of no more than 0.07 pounds per megawatt-hour (MWh)
- Sized to meet the eligible customer generation thermal load
- Operate continuously in a manner that meets the expected thermal load and optimizes the efficient use of waste heat
- Cost-effective, technologically feasible, and environmentally beneficial

On December 21, 2009, the CPUC adopted policies and procedures for purchasing excess electricity from eligible CHP systems by an electrical corporation. The decision adopted two contracts for the purchase of excess electricity: a standard contract for systems up to 20 MW, and a simplified contract for systems no more than 5 MW. This decision was later amended to include an even more simplified contract for systems no more than 500 kilowatts (kW). Contracts offered by the IOUs under the act were based on the cost of a new combined cycle gas turbine and made a location bonus available to qualifying CHP systems.

The “pay-as-you-save” pilot program was not established. Based on comments provided in the CPUC rulemaking, customer interest for an alternative financing program was unclear. No eligible customers or their representatives responded to the ruling. In addition, several utilities provided reasons why this program would not be feasible or suited to the unique circumstances of their service territories. Furthermore, a maximum amount of funding would have to be established to prevent the program from conflicting with existing law that limits lending for utility on-bill financing. To pursue a “pay-as-you-save” pilot program, additional information would be needed, including applicability of federal and state lending laws, the appropriate interest rate for loans, how utility lenders would deal with loan defaults, loan security, credit requirements, and cost recovery. With a lack of customer interest, the CPUC decided it was not worthwhile to pursue the pilot program at the time but had allowed for a petition for modification to revisit the pilot program if new facts and circumstances warrant reconsideration of the decision.

Significant regulatory delays, including three filings with FERC for clarification, prevented the IOUs from filing their tariffs promptly. The issues that were brought to FERC via petition addressed QF status, setting avoided costs, and rehearing. FERC’s replies to those matters, in order, are below:

- On July 15, 2010, FERC found that (1) the CHP generators from which the CPUC is requiring the IOUs to purchase energy and capacity must obtain QF status under the PURPA and (2) the rate established by the CPUC for the standard offer contracts cannot exceed the purchasing utility’s avoided cost.²⁸

²⁸ FERC Docket Nos. EL 10-64-000 and EL 10-66-000.

- On October 21, 2010, FERC issued an additional order which clarified that the state has a wide degree of latitude in setting avoided cost, can use a multitiered, avoided cost rate structure, and that this approach is consistent with the avoided cost requirements set forth in Section 210 of PURPA.²⁹
- On January 20, 2011, FERC denied a rehearing of its Clarification Order issued in October.³⁰

In December 2011, the CPUC approved the IOU advice letters that adopted their AB 1613 Standard Contract and Simplified Contract Tariff sheets (for facilities no more than 20 MW and 5 MW, respectively). An even more simplified contract for systems no more than 500 kW was submitted via advice letter in April 2012 and is pending a CPUC resolution.

By the end of 2011, only one AB 1613 facility has received certification; however, no contract has been signed.

Qualifying Facility and Combined Heat and Power Program Settlement Agreement

Settling parties submitted the *Qualifying Facility and Combined Heat and Power Program Settlement Agreement (QF Settlement)* on October 8, 2010.³¹ This settlement was the result of over a year and a half of negotiations between CHP generation facilities and California's three IOUs. The *QF Settlement* arose out of years of contract and payment litigation among the various parties, as well as the need for a new contracting mechanism to handle the increasing amount of expiring PURPA contracts and the California ISO's Market Redesign and Technology Upgrade (MRTU). This new contracting mechanism, approved by FERC, suspended PURPA for CHP facilities greater than 20 MW and replaced it with a

29 FERC Docket Nos. EL 10-64-001 and EL 10-66-001.

30 FERC Docket Nos. EL 10-64-002 and EL 10-66-002.

31 QF Settlement Agreement Terms Sheet.

<http://docs.cpuc.ca.gov/PUBLISHED/GRAPHICS/124875.PDF>.

competitively bid solicitation program.³² The *QF Settlement* was approved by the CPUC, becoming final and nonappealable on November 23, 2011. This accomplished three clear goals: 1) resolves all outstanding legal disputes, 2) makes available additional power purchase agreement (PPA) options for CHP QFs, and 3) sets out a smooth transition from the existing QF CHP PURPA program to a state-administered CHP program designed to achieve California's GHG reduction goals.

The objectives laid out in this new CHP program by the *QF Settlement* are simple and direct. The utilities will sign 3,000 MW of CHP contracts and reduce emissions from CHP resources by 4.3 million metric tons (MMT). This emissions reduction goal corresponds to the *AB 32 Scoping Plan's* goal for CHP as it is equivalent to the utilities' portion of the goal based on load served.

The transition to this new process will occur over three periods: transition, initial, and secondary. The transition period ranges from the settlement effective date (November 23, 2011) until July 1, 2015. The initial period also starts with the settlement effective date and ends 48 months later. The secondary period starts at the end of the initial period and extends until December 31, 2020.

The 3,000 MW was a negotiated target, which will consist of both new and existing generation achieved through three competitive solicitations by each utility. This contract capacity is divided among the utilities: 1,402 MW for SCE, 1,387 MW for PG&E, and 211 MW for SDG&E. This capacity will be contracted for during the initial contract period, with the exception of SDG&E, which will contract for 160 MW during the initial period and its remaining 51 MW during the secondary period. The contracts will be for 12 years for new, repowered, and expanded facilities, and 7 years for existing facilities (defined as a facility that was operational before the settlement effective date).

During the transition period, QFs with expired or expiring contracts are able to sign a transition PPA to continue operation through the end of this period. During this time, facilities may participate in utility solicitations to obtain a new PPA, decide to sell into the wholesale market, shut down, or cease to export to the grid.

32 In October 2006, FERC issued Order No. 688: "...revising its regulations governing utilities' obligations to purchase electric energy produced by QFs. Order No. 688 implements PURPA section 210(m), which provides for termination of the requirement that an electric utility enter into power purchase obligations or contracts to purchase electric energy from QFs, if the Commission finds the QFs have nondiscriminatory access to markets."

In D.07-09-040, the CPUC recognized that it would need to address the effect of the California ISO's MRTU on short-run avoided cost and the QF program. The MRTU established nondiscriminatory access to markets that allowed the utilities to move toward reforming the QF program in California.

Provided the *QF Settlement* provides a competitive market for CHP resources according to FERC, the utilities are no longer required to offer contracts under PURPA's must-take obligation program to facilities greater than 20 MW.

During the initial program period, each utility will hold three solicitations with specific procurement targets as seen in **Table 3**.

Table 3: Initial Program Period MW Targets as Set Forth in the Qualifying Facility Settlement

Utility	Target A	Target B	Target C	Total
SCE	630	378	394	1,402
PG&E	630	376	381	1,387
SDG&E	60	50	50	160
Total	1,320	804	825	2,949

Source: QF Settlement Agreement Terms Sheet.

During the secondary program period, SDG&E will procure an additional 51 MW, as well as any IOU that still needs to secure its target capacity not met in the initial period. In addition, all the IOUs will procure any additional capacity to meet their portion of their GHG Emission Reduction Targets as established by the CPUC in the Long-Term Procurement Planning (LTPP) proceeding.

GHG emissions accounting will use a double benchmark, one efficiency standard for electricity generation and one for thermal output. The standards are 8,300 British thermal units per kilowatt-hour at higher heating value at the busbar³³ and excluding line losses, and a standard boiler efficiency of 80 percent respectively. “The double benchmark is intended to reflect the GHG emissions that would have occurred if the same amount of electricity and thermal output were obtained from conventional generation resources and a stand-alone boiler.”³⁴

Regulatory Must-Take Generation Tariff Change

Since the inception of PURPA, a regulatory must-take generation (RMTG) scheduling priority was offered to CHP QF resources. With the suspension of PURPA for California’s three IOUs, CHP facilities with a new contract and those with expiring QF PURPA PPAs would no longer be eligible for this scheduling priority. The California ISO created a new tariff to preserve CHP’s scheduling priority to ensure that these system’s host facilities do

³³ The electrical apparatus that connects a generator to the electric grid.

³⁴ QF Settlement Agreement Terms Sheet:

<http://docs.cpuc.ca.gov/PUBLISHED/GRAPHICS/124875.PDF>.

not have to curtail their industrial processes because of an electrical system imbalance.³⁵ The California ISO Board approved this RMTG tariff change on May 16, 2012.

The new policy allows a CHP resource to establish a level of capacity eligible for RMTG scheduling priority, which is limited to the amount of capacity required to meet requirements of the CHP resource's industrial host. QFs with "grandfathered" PPAs will not have to comply with the new requirements until their contracts expire. In addition, the eligibility for RMTG scheduling priority will not depend on status as a QF under PURPA.

Facilities no more than 20 MW will continue to have 100 percent RMTG scheduling priority status. However, they will be subject to other provisions of the tariff change that include revenue metering and telemetry requirements. These provisions extend down to facilities of 1 MW in capacity. Facilities between 500 kW and 1 MW have the option to be subject to these requirements, and facilities below 500 kW are not.

³⁵ The agreements do allow for curtailment in case of a California ISO-signaled emergency.

CHAPTER 3:

Current Regulatory And Policy Environment

Current Regulatory and Policy Environment

The future for CHP in California appears promising, with much of the foundation to achieve its goals in place. The Governor and his administration are highly motivated to see CHP succeed and have indicated their support by establishing a statewide CHP target of 6,500 MW. The utilities and the California ISO, equipped with a relatively new cluster study process, hope to make significant inroads dealing with long interconnection wait-list queues. The IOUs, under the *QF Settlement*, are finishing their first solicitation. The SGIP is back and up and running with greater interest than ever. The emerging technologies/renewable category (for which 75 percent of the funds are reserved) has been fully subscribed in both the PG&E and SCE service territories. The Rule 21 Settlement has been signed and submitted to the CPUC for approval. AB 1613 contracts are available for facilities greater than 500 kW, and the contracts for facilities no more than 500 kW have been submitted for CPUC approval as well. Despite the support CHP has received, the path to reaching California's goals is not clear. This chapter takes a closer look at existing CHP programs and the implications of regulatory developments and policy changes.

Promoting Combined Heat and Power: Self-Generation Incentive Program Competition

When the SGIP was created, conventional technologies received \$1 per watt, fuel cells \$2.50 per watt, and fuel cells that use biofuel \$4.50 per watt. Fuel cells did not have to be used in CHP applications, and conventional CHP technologies were ineligible for renewable funding even if they used renewable fuel. With the exception of fuel cells, CHP projects have not been eligible since the end of 2007. After being excluded from the program for nearly half a decade, the SGIP is once again accepting applications for conventional CHP projects. It will take time for these projects to develop and get underway after such a long hiatus from the program. In addition, there is a security deposit that fulfills its purpose of deterring "ghost projects" from tying up program funds.

In the most recent version of the SGIP, conventional CHP technologies receive \$0.50 per watt and fuel cells \$2.25 per watt for both electric only and CHP applications. The biogas incentive has been altered so that it acts as a \$2-per-watt adder for eligible fuel cells and conventional CHP technologies. While conventional CHP technologies have had their incentive reduced by half, the incentive for fuel cells has only decreased by one-tenth. In addition, fuel cells are still the only CHP capable technology that can be used in electric-only applications.

The revised SGIP allows funds to be moved from one category to another, if need be. Since the emerging technologies/renewable category funds have been reserved for 2012, there will undoubtedly be calls for the remaining 25 percent of the budget that was originally allocated for conventional CHP technologies (internal combustion engines, microturbines, and gas turbines) to be moved to fund the emerging/renewable category. Premature movement of program funds away from traditional CHP technologies could halt projects that are currently being vetted and considered for investment, especially if funds appear in jeopardy. To ensure sufficient funding and reduce risk for conventional CHP, unused funds should not be redistributed to the oversubscribed categories until the end of the year.

There is no difference in incentive for fuel cell projects used in CHP versus non-CHP applications. A fuel cell project with CHP would be more efficient but would also cost the developer more money to install due to the additional equipment required. The cost savings from the heat recovery, specifically for fuel cells because they have a high power-to-heat ratio³⁶, may not be sufficient for the developer to invest the additional funds. Since the SGIP incentive does not distinguish between the two types of fuel cell projects, there is no incentive to choose one over the other. Thus, the most efficient option, a fuel cell project with CHP, may become an electric-only project, which is less efficient, and still receive the highest funding level available in the SGIP.

Electric-only fuel cells are also easier to site. Not having to find thermal sites or specialize each installation to a host's facility allows these electric-only fuel cells to use a plug-and-play business model. In addition, the ability of electric-only fuel cells to make use of directed biogas means that, even under the revised SGIP, these types of projects are eligible for a \$4.25 per watt incentive, only \$0.25 lower than the initial funding level over a decade ago. Evidence suggests that this incentive level is too high and ratepayers may not be getting the most for their money.

In 2010, directed biogas fuel cell projects became the primary recipient of total funds allocated³⁷ by the SGIP.³⁸ The subsequent annual report is not yet available, but staff believes that this trend will continue. Although emerging and renewable technologies receive 75 percent of the annual allotted funds, 2012's funds in PG&E and SoCalGas territory were reserved by the end of April.³⁹

36 Itron, Inc., submitted to PG&E. *CPUC Self-Generation Incentive Program – Tenth-Year Impact Evaluation Report*. July 2011.

37 Paid or reserved.

38 Itron, July 2011.

39 April 16 and April 30 respectively (see CPUC Rulemaking 10-05-004).

Certified Combined Heat and Power Projects Under Assembly Bill 1613

The AB 1613 IOU contracts for projects no more than 20 MW and no more than 5 MW were approved by the CPUC on December 15, 2011. Contracts for projects no more than 500 kW were submitted in April 2012 and are under review at the CPUC. The first CHP system was certified on July 8, 2010. The system, owned and operated by Sonoma County, finished installation and testing, commencing full operation in February 2011. After nearly a year of operation, a contract was finally available for the project to begin receiving payment.

Sonoma County's system uses a 1.4 MW fuel cell that is designed to run 24/7 with minimal fluctuation as dictated by the technology type. This CHP unit allows the site to meet its local thermal needs and help offset its electrical demand. The site has a fluctuating electrical demand, which means that during the day there is not enough electricity to meet its on-site load and at night there is excess. As such, the site buys electricity during the day and exports at night. Since net-energy metering does not apply to fuel cell projects greater than 1 MW in nameplate capacity, this facility decided to use AB 1613 to procure a utility contract.

However, Sonoma County received funds from the SGIP under the 2010 funding cycle. The *2010 SGIP Handbook* does not allow for payment of electricity export, and thus, this project has been delivering and may continue to deliver free power to PG&E until 2015 when the five-year limitations placed on the project by the *2010 SGIP Handbook* expires. However, as part of the most recent SGIP reforms, the *2011 SGIP Handbook* allows payment for up to 25 percent export of net annual generation. This issue was raised at the Energy Commission's *2012 IEPR Update* CHP Workshop.⁴⁰ CPUC and PG&E staff advised the county that the appropriate course of action was to petition the CPUC for a rules change.

Sonoma County contacted the CPUC about such a change and was informed that this change would be possible, but it would likely require the application of additional rule changes, most significantly the new pay-for-performance payment structure. This new payment structure pays half the total allotment up front, with the subsequent funds spread over the next five years as long as the facility performs to predetermined requirements described in the *2011 SGIP Handbook*.⁴¹ If the facility chose to follow the *2011 SGIP Handbook* rules, it would have to return half of its program funds, which would then be redistributed over the next five years. This would ruin Sonoma County's financial plan; therefore, this solution was abandoned.

PG&E is installing a net meter at the site for the benefit of all parties involved. This information will provide more accurate energy accounting. Sonoma County has asked

⁴⁰ http://www.energy.ca.gov/2012_energypolicy/documents/2012-02-16_workshop/2012-02-16_Transcript.pdf.

⁴¹ All CHP and fuel cell technologies are required to meet an 80 percent capacity factor and not exceed a cumulative emissions rate of 398 kg CO₂/MWh; otherwise payments will be reduced.

PG&E to extend to it a traditional, lower-paying, as-available PPA. Sonoma County has indicated that this is its last option, appealing to the goodwill of the utility, asking it to pay for the electricity that is currently being provided to the utility for free.

Difficulties like these illustrate the risks project developers face when determining whether to spend their limited amounts of capital on a CHP project versus buying power from the local utility or other energy investments. Efficient CHP may be the best technology to meet the needs of the developer, as well as support state policy, but because of the perceived financial risks and regulatory uncertainty, many projects are not built.

More recently in May 2012, two additional CHP projects were certified as meeting the guidelines. One of these, a bottom-cycle CHP facility in the Cymric oil field outside Bakersfield, has also run into contractual barriers. This project, put forth by Chevron, was initially designed to interconnect at the same point at which another CHP project already exists. The utility, PG&E, has insisted that connecting at the same point of common coupling would void the existing contract, something Chevron will not risk because the new project would increase the amount of energy purchased under that agreement. Chevron's position is that the project may increase the total energy sold through the existing PPA, but it would not violate the contract as it contains a capacity limit that would not be surpassed. Although a separate meter could be installed and the new CHP system could run independently of the existing system and not interfere with that contract, this option has been a nonstarter for PG&E. Chevron has looked into interconnecting the new CHP project at a different location, but this option is costly as it would require numerous system upgrades. It is unclear whether the project will be built.

The applications have signaled a welcome reception from CHP developers for the AB 1613 feed-in tariff, but none have yet been able to capitalize on its intent.

The Publicly Owned Utilities: Los Angeles Department of Water and Power and Sacramento Municipal Utility District

The three IOUs meet roughly 82 percent⁴² of the state's electricity demand with the remaining percentage being met by a variety of electric service providers, publicly owned utilities (POUs), and other load-serving entities.⁴³ The largest POUs are Los Angeles Department of Water and Power (LADWP) and Sacramento Municipal Utility District (SMUD), which serve nearly 9 percent and 4 percent of California's electrical demand, respectively. Because of their size, these two POUs play a crucial role in helping California meet its CHP policy goals.

⁴² Energy Almanac <http://www.ecdms.energy.ca.gov/elecbyplan.aspx>.

⁴³ Rural electric cooperatives, three small IOUs, one community choice aggregator, and Native American utilities that make up the load-serving entities that serve California's electricity consumers.

CHP systems in LADWP territory consist primarily of projects owned and operated by industrial and commercial customers. These projects total 161 MW⁴⁴ of nameplate capacity and sell excess energy to LADWP under interconnection agreements. LADWP stated in its 20-year planning document, the *2010 Power Integrated Resource Plan* (plan), its intent of “developing CHP target goals to incorporate CHP generation in its future resource mix.” The plan continues: “To encourage customer-developed CHP, shift demand from electric grid, and provide accurate price signals to customer, LADWP is currently offering a standard energy credit to its customers for excess energy they sell to LADWP. The standard energy credit is based on LADWP’s estimated system marginal generation cost and is updated and posted monthly.”⁴⁵ Additional information contained in the plan mentions the consideration of two CHP projects for development, a Terminal Island Renewable Energy Project (4 MW fuel-cell plant using methane gas) and a Los Angeles Bureau of Sanitation Alternative Technologies Projects to convert waste to heat. In written comments, LADWP stated that it “...is pursuing other more cost effective and amenable alternatives over CHP in its service territory...”⁴⁶ while also “currently re-assessing the CHP technology and potential for its service territory and planning to include more robust CHP goals in the 2012 Integrated Resource Plan.”

The *2011 ICF Market Assessment* places the current installed CHP capacity in SMUD’s territory at 464 MW. In 2010, SMUD held a request for offers (RFO) under its feed-in tariff that was made available to solar and CHP resources greater than 5 MW in size. The limit of 100 MW for this program was reached, and its queue was also filled with solar projects. No CHP projects applied to this program before the limit was reached. SMUD is open to receiving “unsolicited offers” for CHP projects and will work with developers, but they may not be eligible for the price or terms offered in the feed-in tariff.

The Investor-Owned Utilities: Analyzing the Qualifying Facility Settlement

The *QF Settlement* is a large step forward in changing the shape of CHP in California. The accomplishment of getting the various parties to the negotiating table and keeping them there for the 18 months it took to reach an agreement is impressive. The *QF Settlement* created a path for existing CHP to sign new contracts with the IOUs as well as a mechanism

44 http://www.lapowerplan.org/documents/final_irp/2010_Power_Integreted_Resource_Plan_without_Appendices.pdf; the *2011 ICF Market Assessment* placed LADWP’s installed CHP capacity at 294 MW, Resource Plan notes 265 MW, LADWP workshop filing notes a reduction to 161 MW because of a refinery closing.

45 Ibid.

46 Submitted for the 2012 IEPR CHP Workshop:
http://www.energy.ca.gov/2012_energypolicy/documents/2012-02-16_workshop/comments/Los_Angeles_Department_of_Water_and_Power_2012-03-09_TN-64067.pdf.

for new facilities to come on-line. However, even with all its success and specificity, questions remain about prospects for new CHP development and what the agreed-upon terms actually mean.

Combined, the three IOUs will sign 3,000 MW of CHP to 7- or 12-year contracts, depending on the nature of the facility. This will be a combination of existing and new CHP projects; how much of each is unknown. The answer to this question will come from the CPUC and the IOUs themselves. When the 2012 IEPR CHP Workshop was held, the IOUs were in the process of reviewing or accepting solicitations and were not at liberty to divulge any conclusive information. The CPUC was unable to provide additional information either, deferring any speculation until hard data comes from biannual IOU reporting. This information is expected to be received by the CPUC in July and become publicly available shortly thereafter.

The GHG reductions are also divided among the three IOUs in the same fashion as the megawatt capacity targets: by percentage of the state's total retail sales. As referenced in the *QF Settlement's Draft Terms Sheet*, using 2007 Energy Commission data would yield 4.3 MMT to the IOUs.⁴⁷ A remaining question for the CPUC was whether the energy service providers and community choice aggregators, to whom the IOUs sell electricity, would be responsible for obtaining their portion of the reductions, 0.5 MMT, on their own or if the IOUs would do it on their behalf. On December 16, 2010, the CPUC clarified in Decision 10-12-035 that the IOUs would be responsible for and allocate costs to the energy service providers and community choice aggregators for their portion of GHG reductions. This combined amount, 4.8 MMT, equivalent to 72 percent of the 6.7 MMT *AB 32 Scoping Plan* goal, was further subdivided for each IOU: 45.6 percent for SCE, 43.9 percent for PG&E, and 10.5 percent for SDG&E. These percentages and the amount of GHG each utility is responsible for reducing will change depending on their share of retail sales in the future.

There is no allocation of GHG reduction targets for the POUs and other load-serving entities as they are outside the jurisdiction of the CPUC. The Draft Terms Sheet only states the settlement parties' position that an estimated 1.9 MMT of GHG reductions "should be the responsibility of the POUs or entities not regulated by the CPUC."⁴⁸ While the *QF Settlement* and its GHG reduction targets are recognized in the *AB 32 Scoping Plan* supplemental materials, only the IOU portion is incorporated as it is "programmatic." There is no discussion of how the remaining reductions will be met if this outstanding portion is not adopted by the POUs. The ARB plans to revisit CHP in a formal rulemaking in 2013.⁴⁹ The debate about targets and their allocation may be raised there.

⁴⁷ *QF Settlement Agreement Terms Sheet*.

<http://docs.cpuc.ca.gov/PUBLISHED/GRAPHICS/124875.PDF>.

⁴⁸ Ibid.

⁴⁹ http://www.arb.ca.gov/cc/capandtrade/assemblyman_fletcher_response.pdf

To understand how the various MW and GHG reduction targets will affect CHP development, it is necessary to understand how the two interrelate and how the GHG accounting will be done. The GHG accounting uses the double benchmark to establish a baseline against which the efficiency of contracted CHP systems will be compared. The double benchmark consists of a heat rate of 8,300 British thermal units per kilowatt-hour at high heating value for electricity generated, and a thermal efficiency of 80 percent. The GHG reductions will be reached by reducing emissions from CHP systems by 4.8 MMT beyond this double benchmark performance standard. This means that there are only three ways to meet this goal: remove CHP systems that do not meet the double benchmark, contract with new or existing CHP systems that exceed the double benchmark, and repower inefficient CHP systems (essentially a combination of the previous two methods).

This method creates the possibility that a majority of emission reductions could come from expiring existing CHP contracts, rather than new CHP capacity. At the 2012 IEPR CHP Workshop, the CPUC illustrated three possible QF Settlement outcomes in its presentation⁵⁰ by applying the three emission reduction options in isolation. The scenarios provided context to the discussion of what each method could provide in the way of GHG reductions. Upon discussion, it was found that the various permutations of combined scenarios at different levels resulted in an overwhelming number of possibilities. Without additional information, further analysis of these possibilities would be purely speculative. Again, hard data and reports from the first IOU solicitations will provide an idea of how these goals will be achieved. The only conclusions that could be reached from the presentation is that it will take a combination of the three methods to reach the QF Settlement emission reduction target, and there is currently no way to determine the amount of new contracted CHP capacity, but it will not be 3,000 MW.⁵¹

Another uncertainty arises about why the IOUs would contract with any CHP systems that do not meet the double benchmark. Some of these systems may be strategically located in the distribution and transmission system where their locational benefits outweigh the added emissions. This further complicates the picture and makes predictions even more speculative.

A caveat concerning the MW target is that AB 1613 projects use a different method for determining efficiency, so CHP installed under AB 1613 will not count toward the IOUs' GHG reduction targets unless it meets the double benchmark. However, those projects will count toward their MW procurement goals. In addition, none of the terms and conditions of the *QF Settlement* apply to AB 1613 projects.

⁵⁰ http://energy.ca.gov/2012_energy_policy/documents/2012-02-16_workshop/presentations/16_Jennifer_Kalafut_California_Public_Uilities_Commission.pdf.

⁵¹ PG&E's first *QF Settlement Semi-Annual Progress Report to the CPUC* under A.08-11-001, dated December 22, 2011, contains 436.1 MW of new contract capacity with existing facilities that will count toward its MW target.

Also contained in the *QF Settlement* are justifications in case the IOUs are unable to meet either their MW or GHG reduction targets. As stated in Section 5.4 of the Terms Sheet:

Any IOU that is unable to meet its MW Target must make a showing to justify its inability to meet the MW Target. Lack of sufficient offers can be used as a reason to justify failure to procure the MW Targets and GHG Emissions Reduction Targets. The efficiency of the CHP Facility participating in the IOUs' procurement programs as compared to the Double Benchmark, offer prices in excess of levels as provided herein, and the amount of GHG emissions reductions may be valid justifications for missing the IOU MW Targets and GHG Emissions Reduction Targets. Lack of need or portfolio fit⁵² arguments shall not be used as reasons to justify failure to procure the MW Targets, but are reasons to justify an inability to meet the GHG Emissions Reduction Targets.

In addition, there is uncertainty surrounding the permanence of the megawatt target. Specifically, there are questions whether the 3,000 MW of CHP that will be contracted for has to be maintained and whether reaching this target relieves the IOUs from further MW obligations.

ARB's GHG reduction targets, although subject to "portfolio fit" provision as noted above, are of greater consequence between the 2015 and 2020 timeframe, as stated in Section 6.7.1 of the Terms Sheet:

If CARB, pursuant to an official CARB document modifies the CARB CHP RRM [recommended reduction measure] to revise the goal of securing 6.7 MMT of incremental GHG reductions from incremental CHP resources, the GHG Emissions Reduction Targets adopted by this Settlement will be adjusted accordingly, so long as the CPUC adopts such modification in the LTPP process. The GHG Emissions Reduction Targets may also be adjusted by the CPUC in the LTPP process, provided that changes in the GHG Emissions Reduction Targets do not affect the MW Targets specified in this Settlement.

However, as with the MW target, a similar question arises with regard to the GHG reduction target about whether IOUs will have a legal requirement to maintain these GHG emission reductions from CHP after December 31, 2020.

These unknowns become more pressing to CHP developers whose only options are either 7 or 12 years in length. Contracts signed in 2012 or 2013 may expire before the end of 2020, the end date of the *QF Settlement*, which makes maintaining the 3,000 MW of contracted CHP a point of greater significance.

Before discussing CHP procurement, it is worthwhile to note the differences among the various sources reporting CHP generation in IOU territories. The *2011 ICF Market*

⁵² Portfolio fit is the measure of a facility's characteristics to a utility's portfolio needs.

Assessment reports *installed* CHP capacity while the CPUC, through IOU data requests, notes the amount of *operational* CHP in **Table 4**.

The Energy Commission also varies in the amount of CHP reported using the *Quarterly Fuels and Energy Report*, which is self-reported data from electricity generators. Discrepancies may be accounted for by nongrid-connected self-generation facilities that are reported, the difference between “installed” and “operational” facilities, as well as data tracking errors such as attributing generation from sites located in SCE territory, but connected to PG&E’s grid or vice versa. The data presented in the *2011 ICF Market Assessment* is the most accurate source of CHP capacity at this time as it takes into account these differences by cross-referencing the various sources of data.⁵³

Table 4: Comparison of Existing Combined Heat and Power Capacity Data

	2011 ICF Market Assessment: Installed CHP Capacity (MW)	CPUC 2009 Data Requests: Operational CHP Capacity (MW)
PG&E	4,768	3,720
SCE	2,580	2,594
SDG&E	363	382

Source: California Energy Commission staff.

Combined Heat and Power in the Investor-Owned Utilities’ Long-Term Procurement Plans

The LTPP Rulemaking provides a biennial review of the IOUs’ procurement process, established under Assembly Bill 57 (Wright, Chapter 835, Statutes of 2002).⁵⁴ The IOUs submit long-term (10-year) procurement plans and comprehensively integrate all CPUC decisions from all procurement related proceedings, which serve as the basis for utility procurement. The proceeding serves as a means to review and approve plans for the utilities to purchase energy and capacity, establish policies and utility cost recovery for purchases, and ensure specified planning reserve margins are maintained.

53 Notable deviations from this (for example, installed capacity in LADWP’s territory) are changes that occurred after the data reconciliation was complete. The Energy Commission is working to keep its database up-to-date, which includes these changes to CHP generation capacity and bringing previously nonreporting *Quarterly Fuels and Energy Report* facilities into compliance.

54 AB 57 was passed in 2002 after the energy crisis, requiring the utilities to resume electricity procurement.

In the IOUs' 2010 LTPP rulemaking, SCE proposed to use the QF Settlement MW targets rather than the standardized planning assumptions as the basis of proposed procurements.⁵⁵ This was approved for the IOUs' procurement activities through 2015. With the exception of SDG&E's 51 MW and any additional capacity assigned in the LTPP to meet the GHG reduction targets in the second program period, all CHP procurement will occur before November 23, 2015, the end of the initial program period. It will then be determined in the LTPP proceeding at the CPUC how much CHP capacity over the 3,000 MW the IOUs will be required to procure.

Also in their filings to the CPUC, SCE proposed to assume zero MW of CHP for the Second Program Period, a position generally agreed upon by PG&E, "on the grounds that the amount of CHP will ultimately need to be procured during that period is subject to change based on a number of factors."^{56 57} This was deemed unreasonable primarily because SCE is forecasting that it will procure fossil generation in the Second Program Period. CHP comes before conventional fossil generation in the loading order, and thus, this proposal was not credible. In addition, CHP facilities no larger than 20 MW may execute contracts after 2015 using the PURPA program and AB 1613. There is also uncertainty about the need to procure additional CHP to satisfy the utility-specific GHG reduction targets in the *QF Settlement*. The CPUC's LTPP decision instructs the IOUs to use the standardized planning assumptions for the Second Program Period instead. This, in and of itself, presents a problem as the decision states: "Because PG&E and SDG&E assert that they are generally free to ignore the standardized planning assumptions, they largely do not take issue with those assumptions."

Going forward, as the 2012 LTPP rulemaking continues, these issues will be raised again. However, by the time the 2014 LTPP rulemaking gets underway, at least two of each of the IOU's competitively bid CHP solicitations will have been held and the results made public. This information will provide enough data to measure the IOUs' progress against the QF Settlement goals and help determine appropriate CHP procurement targets for after 2015.

Cap-and-Trade Implementation

A carbon emissions credit market is being established, more commonly known as cap and trade, as part of the ARB's implementation of AB 32. The goal of cap and trade is to have the

⁵⁵ The 2010 LTPP rulemaking used a midpoint between no incremental CHP and the nearly 4,000 MW or incremental statewide CHP that the ARB targeted in its *AB 32 Scoping Plan*, evenly split between on-site use and export to the grid. (Source: <http://docs.cpuc.ca.gov/efile/RULINGS/130670.pdf>.)

⁵⁶ Rulemaking 10-05-006. <http://docs.cpuc.ca.gov/efile/PD/151314.pdf>.

⁵⁷ SCE's 2010 LTPP Opening Brief sites three factors that may change: ARB's requirements for GHG reduction from CHP, SCE's share of retail sales of energy, and GHG reductions from CHP resources acquired during the first program period.

price of carbon incorporated into the price of energy, both electric and natural gas prices, by 2015. Based on this theory, CHP would be incentivized because efficient CHP reduces overall energy use, resulting in reduced emissions and compliance costs. What was not taken into account is the shift in attributable emissions that occurs with the installation of a CHP facility.

A facility that currently uses a boiler and electricity from the grid will be responsible only for its emissions from the boiler. Emissions attributable to electricity from the grid will be incorporated in the price paid for that electricity. By installing CHP, onsite emissions would increase, even though total emissions would decrease. Two regulations have made this an issue: an emissions compliance threshold, and allocation of emission credits to existing facilities that were meant to ease the transition into cap-and-trade.

The reporting level for facilities that emit GHGs under cap and trade is 10,000 metric tons of CO₂ (MTCO₂) per year, which is being collected by ARB for the first time in summer 2012. Thus, it is unknown how many CHP facilities are actually nearing the compliance threshold or altering their facilities' operations to avoid exceeding the compliance cap. If a facility could avoid the compliance threshold using a boiler and buying electricity, it would cost the facility less but would emit more emissions overall. This outcome is counter to the goal of cap and trade and should be corrected to provide the appropriate incentive to support CHP development and reduce statewide emission levels.

The emissions compliance threshold is 25,000 MTCO₂ per year before the price of emissions is incorporated into the price of energy. This amount is roughly equivalent to a 5 MW generation capacity⁵⁸ and does not take into account other sources of emissions, such as boilers, that may exist at the CHP system site. Facilities that exceed the emissions compliance threshold are responsible for the cost of CO₂, not just in excess of the limit, but up to the limit as well. A CHP facility operator would be motivated to avoid. In addition to undersizing facilities, interested CHP developers opt for utility-generated electricity instead of CHP because of this uncertainty and potential cost.

Industry-dependent energy-use benchmarking limited the allocation of historical emissions-based free emission credits to existing facilities. Using an industry approach to benchmarking was expected to prevent industries from moving out of state to avoid emission compliance costs. The emissions credit would allow the facility to continue its current operations unaffected, or it could choose to sell its credit in the marketplace and reduce its emissions onsite. Selling credits would allow the lowest cost methods for reducing emissions to take place first, and as the price of credits rise, the more expensive emission abatement efforts would follow. The problem with this approach is that new facilities are not eligible for free allocations, so they face the entire brunt of compliance costs

58 AB 1613 requirements limit emissions to 1,100 lb. of CO₂ per MWh. To calculate the equivalent size of generation associated with this emissions amount: (25,000 MTCO₂ per year)/(2,000 tons CO₂ per lb. CO₂) / (8760 hrs per year)(1,100 lb. CO₂) = 5.188 MW.

if they install CHP. As a result, many will opt to buy power from their electric utility, which provides some emission cost buffering (provided by the utilities resource mix of hydroelectric, nuclear, and renewable energy).

These issues would disappear with the full inclusion of emission costs in electricity and natural gas energy prices. This approach will eliminate the need for a compliance threshold, as well as avoid the imbalance created by allocating free credits to existing facilities. If the problems stated above are not addressed in some way as cap and trade is implemented, new CHP investment in the state could continue to decline if emission compliance costs make CHP more expensive than installing a boiler or buying power from a local utility. Once a decision is made to invest in a boiler instead of CHP, it will take 10, 20, or even 30 years before that piece of equipment is depreciated and needs to be replaced. The consequences and lost opportunities that could result from these market inefficiencies could have long-term effects on the potential for CHP development in California. In addition, if this problem is not corrected and cap and trade is not fully implemented (if the price of emissions is not fully included in the price of energy), these problems could become permanent, essentially destroying the market for CHP development for facilities greater than 5 MW.

Cap and trade also affects existing facilities, especially those without utility contracts. These facilities will be responsible for their emissions cost without the ability to pass on this additional cost to the end user of the electricity. There may be numerous facilities without a utility contract as a result of the QF Settlement. The financial implications of cap and trade will no doubt play a large role in their decisions to keep generating or to shut down. Furthermore, because of the short length of the QF Settlement contracts, facilities that are unable to secure a subsequent contract after their 7- or 12-year contracts expire will also face this same decision.

The CPUC is responsible for crediting the revenues raised from the allocation of GHG allowances to electric utilities in accordance to Public Utilities Code 748.5. Senate Bill 1018 (Chapter 39, Statute of 2012), signed into law on June 27, 2012, amends this section and directs the CPUC to credit the funds directly to three groups: residential, small business, and emissions-intensive trade exposed retail customers of the electrical corporations.⁵⁹ Up to 15 percent of the revenues received may be used for clean energy and energy efficiency projects. The first of three state-run carbon allowance auctions for the 2012 – 2013 fiscal year is scheduled for November 14, 2012, so the program may be launched on January 1, 2013. The direction provided to the CPUC by the legislation does not define or specify how to credit the funds among the three groups, so the CPUC opened a proceeding⁶⁰ to receive comments from all stakeholders on how the credits should be allocated. The CHP industry has been an active participant in the CPUC proceeding and has encouraged the ARB to take

59 Rulemaking 11-03-012. <http://docs.cpuc.ca.gov/efile/RULINGS/170472.pdf>.

60 Ibid.

action where possible to ensure that some of the funds are allocated to energy-intensive trade-exposed (EITE) and CHP customers so they are not disproportionately disadvantaged as cap and trade moves forward.

Even if the CHP industry is successful and secures equitable treatment for CHP under cap and trade, the Legislature continues to propose bills that would establish alternate options for determining who will be responsible for allocating funds raised through the cap-and-trade auctions. Proposed legislation, Assembly Bill 1532 (Pérez, 2012), would create an account at the ARB in which all funds collected, excluding penalties and fines, would be deposited. A state board would then award the money, upon appropriation by the Legislature, for measures and programs that reduce GHG emissions and achieve any of the following: clean and efficient energy; low-carbon transportation and infrastructure; natural resource protection; and research, development, and deployment of innovative technologies. The bill passed the Assembly and is making its way through the Senate. This bill, although still subject to amendment, is expected to be signed into law.

Regardless of whether the CPUC continues its rulemaking or the authority is transferred to a new board, special allocation rules and caveats will be required. Without them, cap and trade will become another major disincentive for CHP development in California.

Combined Heat and Power and Once-Through Cooling Retirements

Once-through-cooling (OTC) provides the means of controlling temperature at 19 power plants in California. Of these, 16 plants totaling roughly 17,500 MW are in the California ISO Balancing Area Authority, and three are in the LADWP Balancing Area Authority.⁶¹ To comply with the State Water Resources Control Board's OTC policy, California may have to retire, repower, replace, and/or mitigate more than 13,000 MW of natural gas-fired capacity by 2020.⁶² A major challenge with this transition is that these older power plants are typically located in transmission-constrained areas that require local generation. This presents a unique opportunity for CHP systems.

A significant amount of existing CHP is often located in and/or near load centers where there are applications to use its waste heat. As it happens, some of these facilities are located in prime locations where these facilities could provide system support if some nearby plant that uses OTC is closed. New smaller CHP facilities could be built in these areas, or existing facilities could be expanded. These new or expanded facilities could help alleviate transmission congestion while helping to provide local capacity to meet system and local reliability requirements, including inertia. However, several challenges will have to be

61 *2011 Integrated Energy Policy Report*. California Energy Commission. February, 2012. CEC-100-2011-001-CMF, pp 77, 87.

62 Ibid.

overcome. These include finding prime locations where a host facility is located close to system needs and designing the CHP system so that it meets those needs. If dispatchability is needed, designing an appropriate CHP system may require oversizing⁶³ the CHP unit or putting in a back-up boiler. Doing this would require coordinated planning with the local utility as well as unique contract terms that would allow financial feasibility. Identifying these prime locations where CHP could provide unique and essential system support services is the first step. Once that is done, CHP options can be evaluated against other transmission or generation options, both from technical and financial standpoints.

⁶³ Oversizing means the CHP system would operate below full capacity when meeting onsite peak demand.

CHAPTER 4:

Summary of Combined Heat and Power: 2011–2030 Market Assessment

The CHP policy landscape has changed dramatically since a previous Energy Commission-funded CHP study was conducted in 2009. These changes include the QF Settlement, cap and trade, and the codification of AB 1613, Assembly Bill 2791, Senate Bill 412, and Assembly Bill 1150. To provide relevant information to the CHP discussion, the Energy Commission contracted with ICF in 2011 to study and quantify the long-term market potential for CHP in California and the degree to which CHP can reduce potential GHG emissions over the next 20 years.

This effort led to the report *Combined Heat and Power: 2011 – 2030 Market Assessment*⁶⁴ that uses existing state policies in a Base Case and two additional cases (Medium and High) to show the market effects of additional CHP policy actions and incentives. The additional cases were designed to prompt discussion and provide perspective as to what degree of development may occur if certain policy actions are taken.

The first two steps of the study involved reconciling the various sources of state CHP data and analyzing the technical potential to identify the amount of new CHP capacity that could be built depending on thermal need. The study then applied economic filters to this information for three sets of regulatory scenarios. Other factors taken into account that were not policy-related are technology cost and performance (load factor, power-to-heat ratio), energy prices, capital cost reduction, and market participation.

The Base Case reflects the current policies of using short-run avoided cost pricing for facilities greater than 20 MW in size and AB 1613 pricing for those no larger than 20 MW, the revised SGIP, a 33 percent RPS, and a carbon price.

The Medium Case looks at the policy measures of extending the SGIP beyond its December 31, 2015, end until the phased reductions decrease to zero, and a Market Price Referent (MPR) price for exported electricity from large facilities. Nonpolicy considerations include increased market participation and a higher market response for sectors with a payback period of less than five years.

The High Case considers the policy measures of an allowance for CHP fuel consumption,⁶⁵ elimination of nonbypassable charges, revision of standby reservation demand charge and

64 Hedman, Bruce , Ken Darrow, Eric Wong, Anne Hampson. ICF International, Inc. 2012. *Combined Heat and Power: 2011-2030 Market Assessment*. California Energy Commission. CEC-200-2012-002-REV.

65 CHP will use additional fuel onsite, thus direct emissions associated with its use, even though the total amount of fuel and emissions that would be consumed using conventional generation and boiler technology would be greater.

additional demand charges, a 10 percent investment tax credit, and a \$50 -a-kilowatt-per-year transmission and distribution capacity deferral payment for systems no more than 20 MW. Nonpolicy considerations are an increased focus on power production from export projects, reduction in capital costs, and further increased market participation rates. The cumulative market penetration by scenario is shown in **Table 5**.

Table 5: Cumulative Market Penetration by Scenario

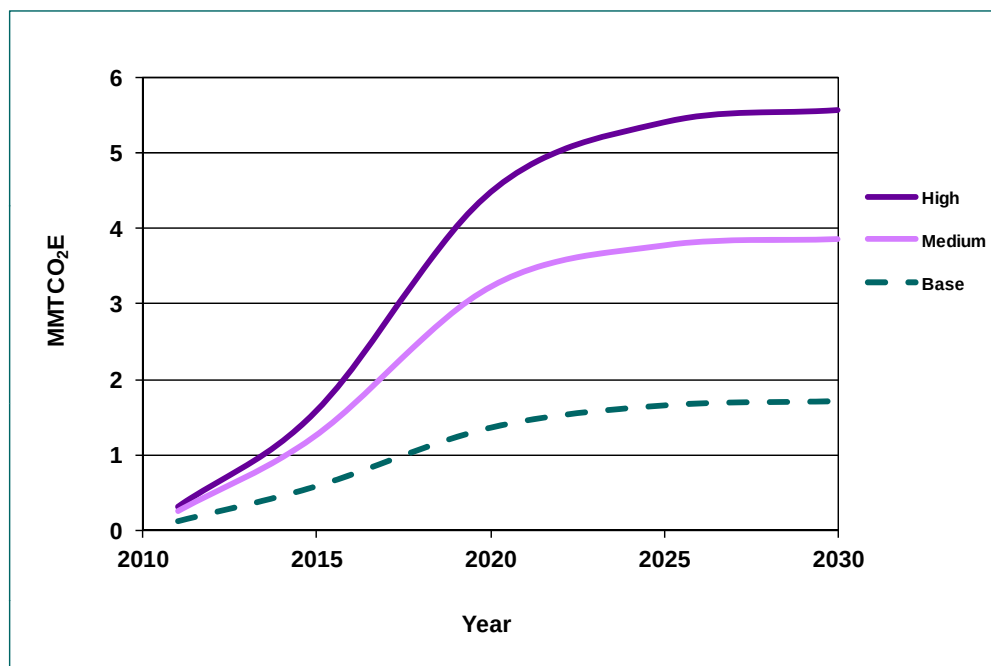
2011 Scenarios	Cumulative New CHP Market Penetration, MW				
	2011	2015	2020	2025	2030
Base Case	123	617	1,499	1,817	1,888
Medium Case	233	1,165	3,013	3,533	3,629
High Case	340	1,700	4,865	5,894	6,108

Source: ICF International, Inc.

Existing *ARB Scoping Plan* assumptions for avoided emissions, including electric line losses and avoided boiler efficiency, are used for the GHG estimates of these developments. The avoided GHG emissions on this basis range from 1.4 MMT to 4.5 MMT in 2020 and 1.7 MMT to 5.6 MMT by 2030. However, the ARB method looks at the reductions in isolation from other statewide reduction programs that are moving forward concurrently, particularly the RPS. If the RPS targets are met in 2020, the avoided utility emissions are only 67 percent of the avoided emissions of the marginal fossil fuel electric system. This accounting method leads to conclusions that run counter the state's and utilities' push to move away from PURPA-style, high-export projects. Onsite CHP use displaces the generation mix of the entire grid. This increased amount of renewable generation reduces the emissions savings from onsite CHP use. Exported CHP generation is assumed to displace the marginal generator, the last one brought on line – considered the one with the highest emission's rate. Thus, exported CHP generation provides greater emission savings when this accounting method is applied.

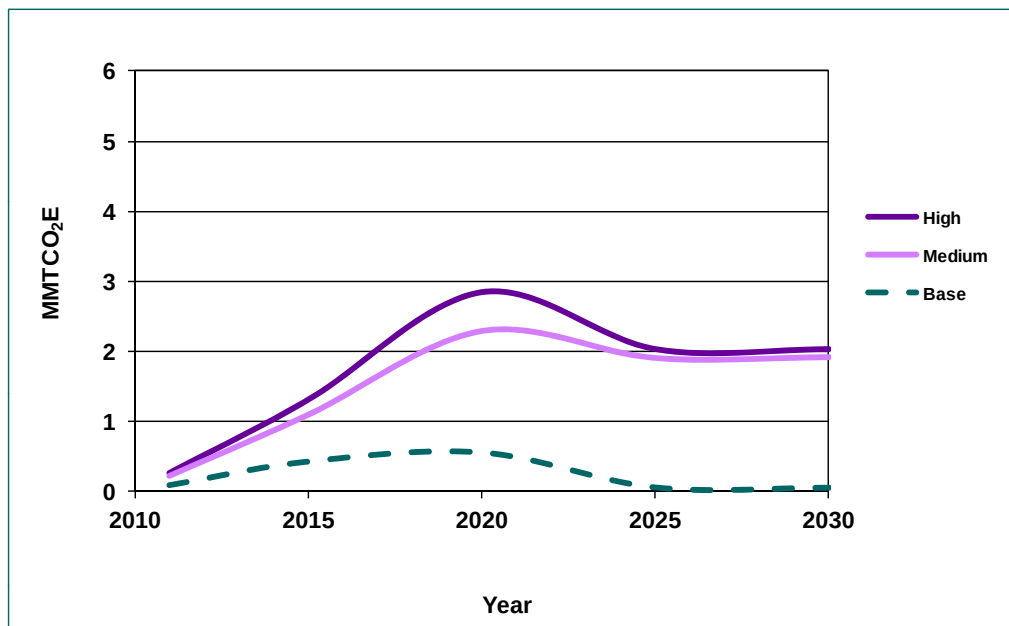
Figure 1 and **Figure 2** provide the GHG emissions savings using different methods. **Figure 1** shows the avoided annual GHG emissions, using the ARB's emission tracking method as stated in the Scoping Plan, ranging from 1.4 MMT to 4.5 MMT in 2020 and 1.7 MMT to 5.6 MMT by 2030. **Figure 2** shows the valuation of GHG emission savings over time with all other statewide programs moving forward concurrently, particularly with the RPS meeting its targets; this results in a declining contribution to GHG emission reductions over time. The Base Case is mostly onsite and reduces utility demand. For CHP that is exported (a higher percentage in the medium and high cases), there is no reduction in benefits because the added CHP capacity is included in the fossil fuel portion of the GHG emissions accounting.

Figure 1: Greenhouse Gas Emissions Reduction From Combined Heat and Power Using ARB Emission Tracking Method



Source: ICF International, Inc.

Figure 2: Greenhouse Gas Emissions Reductions From Combined Heat and Power With Other Emission Reduction Programs Running Concurrently



Source: ICF International, Inc.

Since the study considered the entire state, it is clear that, with the ARB's accounting method, even the most ambitious policy measures considered are insufficient to reach the state's policy goals. In addition, this study does not directly address a number of issues that may prevent the forecasted CHP development from occurring even if all of the policy measures are enacted. These range from interconnection issues to risk associated with regulatory uncertainty, including cap and trade, and the length of contracts available. While the study does note that the large export market will depend heavily on what happens in the LTPP process, it does not comment on the specifics of the contracts offered under the QF Settlement. In the Medium and High Cases, the study assumes an MPR price, while the price paid will be determined by the market, most likely a figure somewhere between the short-run avoided cost and the MPR. As such, capacity that would respond to this price would be less than that indicated in the study. In addition, it is unknown if the contract payment and the short life of the *QF Settlement* contracts will be enough of an incentive to induce private CHP investors to invest in expensive new projects that will take 20 or 30 years to pay off.

CHAPTER 5:

Barriers to Development

Despite the ambitious goals of the state, barriers to CHP development are significant. The *2011 ICF Market Assessment* provided context about the possible development that may result for specific policy actions, which allowed for better discussion in the 2011 *IEPR* CHP Workshop. The 2011 *IEPR* CHP Workshop provided an opportunity for the public and CHP stakeholders to provide input on, among other topics, the barriers to CHP development. This chapter presents the issues that were raised in the workshop and submitted in written comments. The topics addressed in this chapter are working with local air quality management districts, cap and trade, interconnection, nonbypassable and departing load charges, standby and demand charges, additional small CHP barriers, project financing, and utility concerns.

Working With Local Air Quality Management Districts

Meeting local air district requirements can prevent some projects from moving forward, but these requirements vary greatly from one district to the next. This issue is highlighted by National Energy Solution, a company trying to develop CHP projects in California, in its comments, and its concern is intertwined with cap-and-trade issues. To avoid cap and trade's GHG emissions threshold of 25,000 MTCO₂ per year, it has tried to develop projects that use technology that accomplish this. However, because the project was located in a local air district that has stricter nitrogen oxides requirements, it was forced to switch to a different generator. This switch pushed the project over the CO₂ emissions threshold. The project, if it were to be developed, would be responsible not just for its emissions over the limit, but all emissions from the project. This added cost has effectively killed this project and projects like it.

In contrast, East Bay Municipal Utility District commented that it did not have an issue gaining the necessary permits from the Bay Area Air Quality Management District. The district saw the benefit of the proposed project, the addition of a new gas turbine at its wastewater processing facility, and granted a special permit in a timely manner.

Cap and Trade

Cap and trade was identified in the workshop as the greatest uncertainty facing CHP developers. CHP never clearly fit into a single cap-and-trade category – it overlapped the category designed for boilers and the one designed for electricity generators. The regulation as it exists today creates a disincentive to install CHP. The California Large Energy Consumers Association (CLECA) raised the point that new CHP would not get allowances

since it is on-site, even though its load contributed to the utility's share of free allowances. New CHP for EITE customers would not get allowances from ARB since it is new on-site usage after the historical baseline was established. Further, new CHP for non-EITE customers would not get any allowances at all.

Solar Turbines highlighted that cap and trade does not reflect the value of CHP, that the regulation is incomplete, and "if it continues on its present course, would seriously hamper CHP implementation."⁶⁶ Work is still needed if cap and trade is meant to provide the incentive that was recognized in ARB's *Scoping Plan*.

Representatives for the generation facilities ACE Cogeneration and Rio Bravo filed comments concerning the transition period in cap and trade. Under their current contract there is no provision for GHG cost recovery, and the host customer has no incentive to renegotiate the contract. Unless cap and trade is amended, generators will have to absorb this cost. These facilities recognize the need and have the desire to transition to low GHG-emitting fuels, but a pathway to do so does not currently exist. It remains to be seen if the *QF Settlement* will provide the path that allows these facilities to remain an asset to California's electric grid or if they become a stranded asset left behind in the changing regulatory environment.

Interconnection

Interconnection was raised numerous times throughout the workshop, mainly for distributed, small-scale CHP. The Rule 21 Settlement was ongoing at the time of the workshop. As such, it remained to be seen if what developed in this process would be a game changer for CHP developers. The push for Rule 21 reform comes from the fact that the current version of Rule 21 is unable to provide a successful path to interconnection. The proposed settlement was filed on March 16, 2012. While this settlement dealt with some technical⁶⁷ and transparency⁶⁸ reforms, as well as standardizing interconnection applications and agreements⁶⁹, it tabled many of the more contentious issues that will be addressed later in the CPUC rulemaking. On June, 20, 2012, the CPUC issued a Scoping Memo⁷⁰ that set forth a limited number of critical issues that would be addressed in Phase 1 of the rulemaking:

⁶⁶ http://energy.ca.gov/2012_energypolicy/documents/2012-02-16_workshop/comments/Solar_Turbines_2012-03-09_TN-64056.pdf.

⁶⁷ Appropriate engineering analysis of export, non-export, and NEM facilities.

⁶⁸ Procedural clarity, predictability, alignment with wholesale distribution tariffs.

⁶⁹ Uniform application and interconnection agreements across utilities.

⁷⁰ CPUC Rulemaking 11-09-011. <http://docs.cpuc.ca.gov/efile/RULC/169188.pdf>.

- Define the appropriate interconnection study process for all types of generation resources seeking interconnection to the distribution system.
- Create distribution-level interconnection procedures for storage technologies.
- Evaluate and determine appropriate processes for establishing distribution-level interconnection queues (serial or cluster).
- Establish data and reporting requirements.
- Evaluate the need to revise technical operating standards due to advances in technology, communications, and the potential need for the system operator to control these systems.
- Define distinct engineering methodologies based on the characteristics of the resource, such as the resource's impact on the transmission system.
- Establish a path to resource adequacy qualification for resources that have certain characteristics.
- Review and modify, if necessary, the screening mechanism that limits an expedited interconnection to 15 percent of a line section's peak load.

The Scoping Memo also laid out a timeline of 24 months in which to address these issues, as well as a tentative date of September 2012 for a scoping memo that will outline what will be addressed in Phase 2 of the rulemaking. The settling parties recommended leaving the following topics for Phase 2:

- Metering requirements
- Reconsideration of Fast Track size limits and 15 percent screen
- Cost allocation and certainty issues
- IOU reporting on actual cost of system impact studies and facilities studies
- Distribution group study process development
- Reconsideration of timelines, timeline compliance and timeline remedies.⁷¹

This reform process, if it achieves the desired results, will be worth the wait. However, participation in these long and time-consuming regulatory processes by small CHP developers is cost-prohibitive, so they often are not able to present their issues or fully participate in discussions. All the while, these same developers must deal with continuing regulatory uncertainty as they work with customers to develop CHP projects.

CHP developers face additional challenges when interconnecting due to their extensive metering requirements. To qualify for the current CHP projects must record and transfer

⁷¹ http://www.energy.ca.gov/2012_energypolicy/documents/2012-05-14_workshop/presentations/12a_Peterson_CPUC-Rule%2021_Settlement.pdf.

operational data to prove output efficiency. A typical CHP project requires: 1) a thermal meter, which measures thermal output; 2) a gas meter, which measures the gas from the utility; and 3) and a revenue-grade electric generation meter, which measures the electricity generated by the CHP unit. Each meter has a base cost, and the more required features, such as data collection, data exchange, communications, drive the costs upward. Any required telemetry, the real-time data acquisition system that transmits generation information from CHP unit to the utility or California ISO, requires a high-speed data transfer and is extremely expensive. Overall, costs associated with meter installation, instrumentation, and information technology requirements for multiple meters are proving prohibitive for smaller CHP developers (typically 500 kW and below).

For larger facilities that use the utilities' WDAT process, the true effectiveness of the newly approved cluster study remains to be seen. Its two primary objectives are to provide interconnection applicants realistic timelines for completion of studies and early estimates of costs for facility and system upgrades. It is hoped that learning the costs of upgrades earlier, rather than later, will lead applicants to withdraw nonviable projects from the study queue. Queue hogging and projects dropping out of the queue late in the study process often result in the need to redo studies and cost estimates. This is inefficient and costly and can result in projects without deep pockets having to drop out of the process.

Expanding facilities presents its own interconnection issues. East Bay Municipal Utility District's (EBMUD) project required new interconnection studies, a series of site inspections from the utility, and interconnection equipment upgrades, all of which had significant cost and took years to complete. Luckily, EBMUD did not run into the problems that others have had with existing contracts. Energy Producers and Users Coalition (EPUC) has members who would have to give up their existing PPA if a facility wishes to expand using the same point of interconnection. The utility has suggested that, short of giving up its PPA, it would have to interconnect somewhere else. There is no technical argument as to why another generator could not be interconnected at the same point. The facility will not give up its existing PPA to risk participation in the utility's RFO under the *QF Settlement*. Therefore, the only option available is one that carries additional costs that makes the project less financially feasible and, again, deters CHP development.

Nonbypassable and Departing Load Charges

Nonbypassable charges are fees that are levied on customer generators to pay for public purpose programs (also known as the public goods charge), nuclear decommissioning, and cost responsibility surcharge (that includes the California Department of Water Resources Bond Charge and Power Charge, regulatory asset charge, and competition transition charge). Of these, the nuclear decommissioning and cost responsibility surcharge are also known as departing load charges.

CLECA raised the important issue that, for bottom-cycle CHP, the amount of heat available comes with a tradeoff with energy efficiency. That is, by implementing all cost-effective energy efficiency measures first, the amount of heat available to effectively generate electricity may not be sufficient for a feasible CHP project. CLECA maintains that this raises the conflict of how CHP is classified, specifically that CHP as a technology is not considered an energy efficiency measure in California's loading order. Instead, CHP falls under "distributed generation" or efficient use of natural gas, depending on a facility's size. More important, CHP is subject to nonbypassable charges where energy efficiency is not, even in cases where the CHP application will not be exporting electricity to the grid. One of these charges, contained in the public purpose programs, is for energy efficiency programs. The application of this fee is seen as inappropriate by CLECA; CHP should not be hindered by a fee that was designed to promote energy efficiency in the first place.

Customer generation departing load, more commonly known as departing load, are customers who purchase or consume electricity supplied and delivered by customer generation to replace utility purchases. The issue of departing load charges was raised numerous times, specifically by Tecogen, Sonoma County, Solar Turbines, and EPUC. The CHP industry unanimously views departing load charges as excessive and detrimental to new CHP development. EPUC provides specifics on costs: "Current departing load charges, which must be paid by a customer serving its own load, range from \$13.72 per MWh (SCE TOU-8-Sub) to \$22.22 per MWh (PG&E AG-5 customers)."⁷² Solar Turbines states, "CHP and other electric DG technologies are the only customer load reduction measures that face departing load charges."⁷³ EPUC concludes that "departing load charges materially and directly increase the cost of investment in CHP above the cost that would be faced by a utility installing the same facility."⁷⁴

Standby and Demand Charges

Standby charges are fees charged to a customer generator even if no electric service is provided. These charges are intended to cover the investment in infrastructure and generation to serve a customer's full load if they have to shut down their operating generator and rely on utility power. Demand charges are assessed if a customer generator cannot meet its expected performance and relies on its electric utility to meet this gap in

⁷² http://energy.ca.gov/2012_energypolicy/documents/2012-02-16_workshop/comments/Energy_Producers_and_Users_Coalition_and_the_cogeneration_Association_of_California_2012-03-09_TN-64089.pdf.

⁷³ http://energy.ca.gov/2012_energypolicy/documents/2012-02-16_workshop/comments/Solar_Turbines_2012-03-09_TN-64056.pdf.

⁷⁴ Ibid. 66.

energy. Demand charges are based on the peak electricity demand during a given period, typically one month.⁷⁵

Tecogen and Sonoma County provided an example of these charges at the 2012 IEPR CHP Workshop. Facilities that shut off, for one reason or another, are immediately assessed a significant demand charge for using the utility service and then are required to pay for the electricity that is consumed. What is at issue here is the amount of the charges and whether these charges are reasonable.

These fees are especially detrimental to small projects; not operating during a peak hour can erase the entire savings that a generator has provided for the month of service. Many times, the source of the problem is unknown. Sonoma County incurred more than \$110,000 in demand charges, in addition to the energy it had to then procure, over the one-year period from March 2011 to 2012. This cost adds significant risk to small CHP projects, increasing payback time and deterring investment.

Additional Small Combined Heat and Power Barriers

Tecogen raised two additional issues that are worth mentioning in regard to barriers to small-scale CHP development. The first is metering requirements, and the second is net energy metering (NEM). The California ISO and the utilities are pushing for increased visibility and metering of smaller CHP projects, down to 500 kW. This increased transparency comes at increased cost, including the cost of meters for the electric generators.

The second issue Tecogen raised is net energy metering. CHP facilities are not eligible for NEM, unless they use biogas or are a fuel cell. NEM projects have to be one megawatt or less, sized to meet their annual load instead of peak demand. During times of high generation and low use, NEM projects “feed back” electricity to the grid. This raises two concerns. One, fuel cells can qualify even if they are not used in a CHP application, while traditional CHP technologies do not qualify. Two, traditional CHP facilities that may have the same generation and “feedback” profile as a NEM project are subject to different studies. NEM projects qualify for a “fast track” study under Rule 21. A similar project, because it “exports,” has to follow a traditional study timeline that is also more expensive. These differences are strictly regulatory in nature, posing significant disadvantages for CHP projects.

SDG&E makes the following point about NEM: “Net metering for CHP on a flat rate allows the CHP owner to sell power in low price hours in the middle of the night when power is not needed for their operation and receive high-valued, on-peak power from the utility at the same price. Net metering for flat-rate customers obliterates the price signal and obscures

75 US EPA. *Standby Rates for Customer-Sited Resources*. December, 2009.
http://www.epa.gov/chp/documents/standby_rates.pdf.

the level of subsidy. Net metering for CHP should not be considered in order to maintain appropriate price signals and to make clear the level of subsidy; that way consumers and regulators alike can make informed choices.”

Project Financing

The economic viability of installing CHP for most customers requires interconnection with the local electricity grid for backup and supplemental power needs and, in some cases, exporting excess power to the grid. No single source of funds is enough to spur CHP development. As noted by EBMUD and Sonoma County in the workshop, upfront funding from state programs helped in making the decision for installing CHP. The Waste Heat and Emissions Reduction Act also helped make the project more viable. But even with these incentives, the barriers mentioned above add up and often result in a no-project decision. No single barrier can take credit for preventing CHP development; it is the culmination of these numerous barriers that do.

Utility Concerns

The utilities all expressed concerns about reaching the state’s CHP goal. “PG&E is concerned that the current analysis is not sufficiently robust to consider CHP in the broader framework of California’s energy policies and whether CHP will help achieve California’s energy and environmental goals.” SDG&E raises similar concerns: “Without coordination and analyses of interrelated mandates, California will find itself out of ‘degrees of freedom’ in resource planning by adopting multiple mandates in isolation of one another.” SDG&E continues: “The focus should be on setting the right targets in light of the state’s 2050 goals, the cost-effectiveness of the CHP technology, the desire to avoid stranded costs, and the impact on electricity rates.”

The utilities provided additional guidance for what they desire from new CHP development. PG&E believes “preference should be given to projects that reduce GHG emissions while offering the most operating flexibility to accommodate electricity from intermittent generators.” SCE expresses a similar belief: “Only CHP that can provide cost-effective GHG reductions relative to other GHG reducing measures should be pursued.” PG&E also offers the recommendation that for evaluating the emissions reductions that CHP provides there is “the need to focus on actual emissions, not solely the emission reduction formula set forth in the *ARB’s Scoping Plan*.”

In the meantime, the utilities do not think any additional action is necessary. “PG&E does not support additional regulatory changes at this time... Sufficient time should be allowed to implement these existing policies, and to gather “lessons learned” before layering on more initiatives....” PG&E believes California should conduct a number of assessments, including under what circumstances CHP reduces GHG, how much it will cost to achieve

GHG emissions from CHP versus other choices, who should bear the increased cost, and the circumstances for CHP generation to meet the requirements for the generation attributes identified in the long-term planning process. "Absent such an assessment, there should be no legislative recommendations," PG&E states. SDG&E agrees with this conclusion, commenting on the Market Assessment that "there is not enough information provided to allow for policy makers to decide on regulatory changes." This belief is also echoed by LADWP: "There needs to be additional study and analysis of CHP potential in specific POU service territories...."

LADWP lists several challenges it faces for CHP development including feed-in-tariff costs, emission concerns, noise abatement, space limitations, maintenance costs, and lengthy interconnection agreements. Despite these obstacles, "LADWP believes CHP should not be subsidized because: CHP provides excess power off peak when least needed; CHP competes with and does not assist in RPS integration; Feed-in Tariffs should provide a stable pricing for excess electricity and they are or have already been implemented by the utilities; CHP export power can provide the needed volt-amp reactive support if it's dispatchable; and the current utility emission credit allocation was determined based on emission reduction forecasts that include DG (CHP including) and there are no additional expected emission credits beyond those forecasted."

CHAPTER 6: Recommendations

California's CHP fleet has been decreasing in size over the past seven years. The Governor's goal is to increase CHP capacity by 6,500 MW. That means maintaining the existing capacity of roughly 8,500 MW and adding to it for a total installed capacity of 15,000 MW. For reference, California's projected coincidence peak is expected to be 75,000 MW in 2020. The *QF Settlement's* 3,000 MW target, incorporated into the utility's LTPP, will be composed of both existing and new CHP. The existing fleet will not all continue to operate; there will be retirements. This new capacity does not come close to the Governor's goal. Recommendations and actions to move toward this goal are examined in this chapter.

Financing and Regulatory Barriers

As the electric grid changes, the role for CHP will have to change to meet evolving system needs. Electric system planning used to focus on how to meet demand cost-effectively using base load technologies and expensive gas-fired peaking plants to schedule around the other available resources. State policy has added numerous other conditions to the cost minimization constraint, most prominently the RPS. This additional focus, maximizing energy from renewable resources, has shifted the way other resources are valued. While CHP is still an important resource to reduce demand and provide efficient use of natural gas, waste heat, and waste gas resources, its value to grid operators has changed. Energy from a CHP resource under the must-take obligation is seen as just one more resource that grid operators have to schedule around. Under PURPA, CHP resources were must-take; all of their export generation had to be purchased for a contracted price. The California ISO RMTG tariff change and the *QF Settlement* have changed this situation. The amount of must-take energy is limited to that needed for a facility's on-site thermal needs. Remaining capacity can bid into the various California ISO markets.

In response, the old way of thinking about how to design CHP systems needs to change, and along with it, the processes that dictate how CHP operates. This will require developing new creative business models, flexibility in contracts, and RFOs that recognize the contribution that CHP resources can make to improve system stability and reliability. Without these changes, CHP projects will have limited economic incentives to participate and be integrated into the dynamic grid of the future. However, it does not necessarily follow that just because a market for energy, capacity, and other services develops that CHP projects will come to fruition. Some things do not change; cost certainty through long-term contracts is still the way projects get built. Twelve-year contracts for 20- to 30-year investments may not be sufficient to stimulate private sector investment in new CHP development. The existing payment method for these services may also not be sufficient to overcome the risks of building a project capable of providing them.

Rethinking the design of CHP projects will include considering oversizing CHP generation for a more dispatchable resource, the possibility of installing back-up high-efficiency boilers for possible curtailment, and making these options financially feasible. A major obstacle to these proposals is that oversized generation or the use of back-up boilers in this manner will change the emissions profile of CHP resources. Depending on the emissions accounting method, these facilities may appear to be more polluting. However, when compared to other methods of meeting the grid's electrical needs such generation would provide, like conventional gas turbines used for spinning reserve, it may prove cleaner on balance.

If the utilities are serious about changing the way CHP operates so it supports system operations, they should look into joint funding of projects with third parties that are in locations where the benefits of CHP can be optimized. In its comments, SDG&E raises some relevant issues: "Since CHP is located on customer property and is providing thermal and electrical energy to the customer, there are significant barriers to utility participation in owning CHP. In addition, under the QF Settlement new utility-owned CHP does not count toward the MW targets and can count only up to 10 percent of the CHP GHG reduction targets." Allowing the utilities to play a larger role in CHP development – working with developers and customers to create projects that meet both the utility's system needs as well as a facility's on-site needs — will be necessary if the role that CHP plays in the electric grid is to grow.

Departing load charges, cap-and-trade costs, the lack of an export market for excess generation, and interconnection costs are just a few of the uncertainties that make project financing a much larger issue. Finding private sector financial backing for projects that face so much uncertainty is difficult for many developers. The state's inconsistent backing of CHP illustrated by the possible financial burden of cap and trade makes investors wary. This risk, perceived or real, increases the cost of financing projects. Providing financial assistance to clean, efficient CHP projects in the form of project screening for technical and financial feasibility as well as education and outreach about state programs, such as the SGIP and AB 1613, will help decrease this risk. However, reducing risk is the goal, and showing strong state support for CHP by reducing existing barriers will have more tangible results for CHP development than creating new incentive programs.

New business models alone, however, will not address the continuing regulatory barriers that discourage the development of CHP in California. These barriers were identified in the 2012 IEPR CHP Workshop:⁷⁶

- Cap-and-trade provisions
- Demand charges, standby charges, and departing load charges
- Interconnection and metering costs and requirements

⁷⁶ 2012 IEPR Lead Commissioner Workshop on Combined Heat and Power in California, February 16, 2012.

- Lack of NEM eligibility
- Lack of a long-term (beyond 2015) CHP goal in LTPP

In its current form, cap and trade is a disincentive to invest in clean, efficient CHP. The outcome of pending legislation will determine who will be responsible for correcting this regulatory oversight. Two courses of action are possible to restore CHP's natural advantage gained through its net efficiency over separate electric and thermal generation: 1) the agency that is responsible for allocating collected funds, whether the CPUC or some other state board, should provide compensation to CHP during the cap-and-trade implementation period; or 2) the ARB should revisit the cap-and-trade provisions that apply to CHP.

The accounting method used by the ARB in its *Scoping Plan*, as identified in the 2011 ICF *Market Assessment*, leads to the conclusion that exported electricity from a CHP project reduces more greenhouse gases than electricity used on-site. The state's preference for DG resources, whose electricity is consumed on-site or locally, runs counter to the adopted method. In addition, utilities have moved away from high-export PURPA-style projects, the very projects that, using this method, produce the greatest greenhouse gas reductions. This is a problem CHP facilities will have to deal with unless CHP electricity consumed on-site is taken into account when calculating the total energy generated when calculating the RPS. This is what happens when electricity is exported; it becomes part of the utility's RPS calculation. For the most efficient, least polluting result, CHP should be incorporated into the RPS calculation, allowing all electricity generated, on-site or exported, to be compared to the utility's marginal, or least efficient, generator. If this change does not occur, CHP will be forced to compete with grid electricity that is ever increasing in its percentage of renewable resources. This is a competition that CHP cannot win. CHP may be cleaner than the utility's marginal generator but may not be to the grid's entire resource mix.

It has been nearly a decade since demand, standby, and departing load charges were established. Since then, actions have been taken that allow certain technologies or size of technologies be exempt from these charges. CHP stakeholders believe that the current regulatory environment will not lead to the desired results as stated by the state's policy goals in regards to CHP. The charges should balance costs incurred serving CHP generators while taking into account all the benefits those generators provide and the state's policy goals.

Interconnection is a long, and often costly, process. While this is difficult for new facilities, it is even more complicated for facilities that are expanding their operations behind a common point of coupling. Any expansion requires a full interconnection study, a two-year process. The difficulty is only increased when dealing with existing contracts. Interconnecting at an alternate junction is not always an option, and when it is, it typically costs more as it requires more extensive equipment upgrades. As the state looks towards increasing the size of its CHP fleet and once-through cooling plant retirements, the number of these projects

will only increase. As such, interconnection requirements for generation expansion at existing facilities should be eased.

Meters are necessary, but also an additional financial burden on developers, and may prove redundant as more of them are required to meet the requests of the utilities, the California ISO, and state regulatory agencies. Creating new ways to capture thermal efficiency ratings, and looking at ways to standardize metering requirements and reduce their costs, both to the technology and to the developer, should be a policy priority.

The time-of-generation argument that invalidates CHP's inclusion in the NEM program that SDG&E articulated earlier ignores the facts that wind generation is primarily at night, and fuel cells operate around the clock. Both of these technologies are currently eligible for the program. Net metering should maintain the appropriate price signals when dynamic pricing becomes a reality, but in the meantime NEM eligibility should be technology-neutral. If the CPUC wishes to take into account the time-dependent aspect of electricity generation for NEM-sized projects, it should do so without a technology bias.

Actionable Items

- The CPUC should allow a larger percentage of new utility-owned or co-owned CHP generation to count toward the utilities' GHG reduction goals. The CPUC, with aid from the utilities and CHP advocates, should create a legal framework that allows flexibility in RFO proposals and PPAs.
- Either the CPUC, through the use of cap-and-trade funds, or the ARB, through the allocation of emission allowances, should restore the natural advantage CHP has through its efficient use of fuel so it is not disadvantaged by the implementation of cap-and-trade.
- The Legislature should amend the RPS program to either exempt electricity purchased from CHP resources that are more efficient than the local utility's marginal generator from the calculation of total retail sales, or include all electricity generated from CHP resources in a utility's territory in the calculation of total retail sales.
- The CPUC should revisit demand charges, standby charges, and departing load charges as they apply to CHP resources.
- The various agencies should evaluate the interconnection requirements in their jurisdiction (Rule 21, the Wholesale Distribution Access Tariff, and Generator Interconnection Procedures) to ease the process of interconnection at facilities that expand their generation capabilities.
- The Energy Commission should analyze the various metering requirements across programs and agencies to consolidate the requirements.

- The Electric Program Investment Charge program⁷⁷ should identify technical research necessary to reduce costs and develop uniform meter standards for all state and federal jurisdictions including the SGIP, utility telemetry requirements at the distribution level, and California ISO telemetry requirements at the transmission level.
- The state regulatory agencies should implement the recommendations that result from the metering requirement analysis and research and revisit the rules that govern net-energy metering eligibility.
- The Energy Commission should explore ways to provide financial assistance to clean, efficient CHP projects.

Long-Term Planning

The success of the RPS is seen as a viable pathway for CHP developers to achieve the state's CHP goals. Developers and CHP manufacturers saw the barriers to solar resource development fall away once an RPS was put in place. Many of the charges that other generators, including CHP, have to pay, such as standby charges and departing load charges, are not charged to renewable resources. In addition, renewable energy projects have numerous additional incentives ranging from waiving interconnection study fees and metering equipment cost subsidies to a higher-paying feed-in tariff and NEM eligibility. A portfolio standard may not be necessary in itself to encourage CHP, but it has removed barriers, created incentives, and produced tangible results for renewable resources.

Utilities and others have indicated they do not support a mandate or portfolio standard for CHP. If a portfolio standard is considered, a number of additional issues should be addressed. CHP needs to be located at thermal loads, and these are not evenly distributed among the utilities. Since these facilities are located at private facilities, they require more collaboration with owners; utilities cannot simply go out and build these facilities on their own. Additional RFOs could be held in a similar fashion to the *QF Settlement*, with caveats that development would best meet both system and host-site needs.

The dichotomy between what the utilities want and what developers need to meet the state's CHP goals is seen most clearly at the CPUC where various parties advocate for how much CHP development should be included in the utilities' LTPPs. The utilities have presented very low numbers, including zero development after 2015. While zero, as the CPUC has stated⁷⁸, is less reasonable, an appropriate target for development after 2015 is still open to debate and will most likely be a focus of the 2014 proceeding. For large-scale

⁷⁷ The portion of the Electric Program Investment Charge program administered by the Energy Commission will provide funding for applied research and development, technology demonstration and deployment, and market facilitation for clean energy technologies and approaches for the benefit of ratepayers of PG&E, SDG&E, and SCE.

⁷⁸ CPUC Decision 12-01-033, pp 32-33.

CHP, maintaining a placeholder for future CHP development in the LTPPs is essential. If CHP is seen as the residual resource after other resource procurement is planned, efficient CHP will be undervalued and its procurement argued against for lack of need. In light of the effectiveness of the RPS, the importance of a long-term goal in the utilities' LTPPs, and the lack of serious targets being presented by the utilities in those LTPPs, a CHP portfolio standard may be the only viable option if barriers to CHP development remain, and the state is unable to reach its goals.

Actionable Items

- The Energy Commission should reach and educate both the private sector and the public about the opportunities and benefits provided to CHP to encourage participation and support in existing programs for CHP.
- The Energy Commission and CPUC should continue to track, analyze, and report to the Governor and Legislature on the progress of the *QF Settlement*, AB 1613, and other state programs designed to encourage new CHP.
- The Energy Commission should revisit and update the CHP technical assessment in late 2013 or early 2014 to provide information on CHP development for the 2014 LTPP proceeding. This will also provide an opportunity to assess the effects of cap-and-trade on CHP before its full implementation in 2015.
- Depending on the progress toward meeting the state's CHP capacity target and the recommendations listed here, the state should consider a CHP portfolio standard.

Acronyms

Acronym	Definition
AB	Assembly Bill
ARB	California Air Resources Board
California ISO	California Independent System Operator
CCA	community choice aggregator
CHP	combined heat and power
CLECA	California Large Energy Consumers Association
CO ₂	carbon dioxide
CO ₂ E	carbon dioxide equivalent
CPUC	California Public Utilities Commission
DG	distributed generation
EBMUD	East Bay Municipal Utility District
EITE	energy-intensive trade-exposed
Energy Commission	California Energy Commission
EPUC	Energy Producers and Users Coalition and the Cogeneration Association of California
FERC	Federal Energy Regulatory Commission
GHG	greenhouse gas
GIP	Generator Interconnection Procedure
<i>IEPR</i>	<i>Integrated Energy Policy Report</i>
IOUs	investor-owned utilities
kW	kilowatt
LADWP	Los Angeles Department of Water and Power
LTPP	Long-Term Procurement Plans
MMT	million metric tons
MPR	market price referent
MRTU	Market Redesign and Technology Upgrade
MT CO ₂ E	metric tons of carbon dioxide equivalent
MW	megawatt
MWh	megawatt-hour
NEM	net energy metering
OTC	once-through cooling
PG&E	Pacific Gas and Electric Company
PPA	Power Purchase Agreement
PURPA	Public Utility Regulatory Policies Act
QF	qualifying facility
RFO	request for offers
RPS	Renewables Portfolio Standard
SCE	Southern California Edison
SEC	standard energy credit
SDG&E	San Diego Gas & Electric Company
SGIP	Self-Generation Incentive Program
SMUD	Sacramento Municipal Utility District
WDAT	Wholesale Distribution Access Tariff

