COMMISSION REPORT

IMPLEMENTATION OF AB 1613

THE WASTE HEAT AND CARBON REDUCTION ACT

COMBINED HEAT AND POWER SYSTEMS

FINAL STATEMENT OF REASONS

CALIFORNIA
ENERGY COMMISSION

Arnold Schwarzenegger, Governor

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ABSTRACT

The Waste Heat and Carbon Emission Reduction Act (Assembly Bill 1613) mandates that California policies advance the efficiency of the state's use of natural gas by using excess waste heat through combined heat and power technologies. The Final Statement of Reasons describes the California Energy Commission staff's processes for developing the eligibility requirements for new combined heat and power systems to qualify for incentive programs developed by the California Public Utilities Commission and publicly owned utilities, including (1) programs for the purchase of excess power generated by qualifying combined heat and power systems, and (2) a pilot program providing for on-bill financing to assist nonprofit and government entities with the upfront costs associated with the purchase and installation of qualifying combined heat and power systems.

Keywords: Bottoming cycle, carbon dioxide emissions, combined heat and power, CHP, export tariff, fuel efficiency, greenhouse gas emissions, NO_x emissions, supplementary firing, thermal output, topping cycle, waste heat recovery, waste heat utilization

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CHAPTER 1: Introduction

On December 17, 2008, the California Energy Commission issued Order No. 08-1217-16 instituting a rulemaking proceeding to implement the Waste Heat and Carbon Emissions Reduction act, codified in Sections 2840 through 2845 of the Public Utilities Code.[1] This rulemaking process is consistent with and furthers the objectives of the Legislature , which found, in Public Resources Code Section 25004.2, "cogeneration technology…should be an important element in the State's energy supply mix…can assist meeting the state's energy needs while reducing the long-term use of conventional fuels…reduces negative environmental impacts…and that cogeneration should receive immediate support and commitment from state government."

The Final Statement of Reasons describes:

- The specific purpose for each performance requirement, as contained in the Energy Commission adopted *Guidelines for Certification of Combined Heat and Power Systems Pursuant to the Waste Heat and Carbon Emissions Reduction act*, mandating that a combined heat and power (CHP) system must meet certain specified guidelines to qualify for the incentive programs to be developed by the California Public Utilities Commission (CPUC) and publicly owned utilities. This includes (1) programs for the purchase of excess power generated by qualifying CHP systems, and (2) a pilot program providing for on-bill financing to assist nonprofit and government entities with the upfront costs associated with the purchase and installation of qualifying CHP systems.
- The rationale for each performance requirement.
- The rationale for filing for certification as a qualifying CHP system.
- The rationale for annual reporting of CHP system performance in order to maintain status as a qualifying CHP system.

The Energy Commission, the CPUC, and the California Air Resources Board (ARB) have responsibility for implementing various provisions of the act, which contains the following specific directives regarding CHP system performance:

- The CHP system generating capacity shall not be more than 20 megawatts (MW).
- The eligible customer-generator shall use a time-of-use meter capable of registering the flow of electricity in two directions.
- The CHP system shall meet a minimum efficiency standard of 60 percent measured as useful energy output divided by fuel input, based on 100 percent load.

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1. The act was enacted through Assembly Bill (AB) 1613 (Blakeslee, Chapter 713, Statutes of 2007) and amended in AB 2791 (Blakeslee, Chapter 2553, Statutes of 2008).

- The CHP system shall meet an oxides of nitrogen (NO_x) emissions rate standard of 0.07 pounds per megawatt hour (MWh). A system meeting the 60 percent efficiency standard may take a credit of 1 MWh for each 3.4 million British thermal units of heat recovered to meet the NO_x standard.
- The CHP system shall be sized to meet the eligible customer-generator's thermal load.
- The CHP system shall operate continuously in a manner that meets the expected thermal load and optimizes the efficient use of waste heat.
- The CHP systems shall be cost effective, technologically feasible, and environmentally beneficial, particularly with respect to carbon dioxide and other greenhouse gases.
- The CHP system shall comply with the greenhouse gas (GHG) emission performance standard under to Public Utilities Code Section 8341 (GHG emissions from baseload power plants).
- An eligible customer-generator shall adequately maintain and service the CHP system so that the system continues to meet or exceed efficiency and NO_x and GHG emissions standards.

The act also contains the following general directives:

- The CHP system shall commence operation on or after January 1, 2008.
- The guidelines shall not permit eligible CHP systems to become de facto wholesale generators with guaranteed purchasers for their excess electricity.

The Final Statement of Reasons includes necessary background information to show that the guidelines address the requirements of the act and to allow the stakeholders to understand why specific requirements were selected.

CHAPTER 2: Procedural Issues

The act requires the Energy Commission to adopt the final guidelines by January 1, 2010.

The CPUC opened an Order Instituting Rulemaking (OIR) R.08-06-024 on June 26, 2008, to implement the provisions of the act to the CPUC. The OIR process parallels the Energy Commission's rulemaking proceeding. The CPUC issued Decision 09-12-042 on December 21, 2009, adopting policies and procedures for the purchase of excess electricity from eligible (CHP) systems by an electrical corporation. The decision adopted two contracts for the purchase of excess electricity: a standard contract will be available to all eligible CHP systems up to 20 (MW), and a simplified contract will be available to CHP systems that export no more than 5 MW. Contracts offered by the investor-owned utilities' (IOUs) under the act will be based on the costs of a new combined cycle gas turbine, and a location bonus will be available to qualifying CHP systems. Unless otherwise exempted, all California electrical corporations must offer these contracts. This rulemaking remains open to address implementation of a "pay-as-you-save" program.

The act requires the ARB to report to the Governor and the Legislature by December 31, 2011, on the reduction of GHG emissions resulting from CHP systems and to recommend policies that further the goals of the act. The ARB has been conducting numerous activities related to AB 1613 in its implementation of AB 32 (Núñez, Chapter 488, Statutes of 2006), the Global Warming Solutions Act of 2006.

The Greenhouse Gas Mandatory Reporting Regulation, approved by the ARB in December 2007, provides information that assists development and implementation of strategies to reduce GHG emissions. Under the requirements of AB 32, those mandatory reporting regulations must use rigorous and consistent emission accounting methods and provide for verification of reported emissions data. The ARB's GHG Mandatory Reporting Webpage can be found at: http://www.arb.ca.gov/cc/reporting/ghg-rep/ghg-rep.html.

The Energy Commission's Electricity and Natural Gas (E&NG) Committee, the Integrated Energy Policy Report (IEPR) Committee, and Energy Commission staff conducted three workshops during the rulemaking. Energy Commission staff released and reviewed comments on its processes and concepts for the guidelines. The schedule leading to Energy Commission adoption of the guidelines is summarized below:

- April 13, 2009 – E&NG Committee Workshop
- July 22, 2009 – Staff Draft Guidelines posted to Docket 08-WHCE-1
- July 23, 2009 – IEPR Committee Workshop on CHP
- August and September 2009 – Stakeholder comments submitted to docket. Informal discussions with stakeholders

- October 1, 2009 – Revised staff draft guidelines, application, and annual reporting forms, and responses to comments posted
- October 12, 2009 – Electricity and Natural Gas Committee workshop on CHP guidelines, forms, and responses to earlier comments
- October 19, 2009 – Comments due to Docket 08-WHCE-1
- November 23, 2009 – Notice of Proposed Action, Committee Guidelines, Staff's "Draft Initial Statement of Reasons" publicly available
- January 13, 2010 – Modified committee guidelines posted
- January 25, 2010 – Comments due
- January 27, 2010 – Energy Commission adopted final guidelines at a business meeting
- March 17, 2010 – Modified final guidelines posted for comment
- April 1, 2010 – Comments on modified final guidelines due
- April 7, 2010 – Energy Commission adopted modified final guidelines at a business meeting

CHAPTER 3: Information Sources Used To Formulate Guidelines

A number of California, national, and international proceedings and programs address CHP system performance requirements, CHP as a greenhouse gas mitigation measure and require reporting of CHP system performance.

The CPUC administers the Self-Generation Incentive Program (SGIP) as part of its response to Assembly Bill 970 (Ducheny, Chapter 329, Statutes of 2000), which provided incentives for distributed generation technologies, including CHP systems, until December 31, 2007. The *SGIP Handbook* includes program eligibility criteria and requirements, application process, and other installation requirements and continuing site access requirements. The *SGIP Handbooks* were developed collaboratively by the CPUC, the Energy Commission, and IOUs over several years.

Assembly Bill 2778 (Lieber, Chapter 617, Statutes of 2006) required the Energy Commission, in consultation with the CPUC and ARB, to evaluate the SGIP and the costs and benefits of expanding eligibility for the program to renewables. The consultant report prepared for the Energy Commission found that reciprocating engine and turbine technologies, especially those in CHP applications and/or when using renewable fuels, can reduce air quality pollutants and use greenhouse gases.[2]

Senate Bill 412 (Kehoe, Chapter 182, Statutes of 2009) extended eligibility for incentives under the SGIP to distributed energy resources that the CPUC, in consultation with the ARB, determines will achieve reductions of GHG emissions directed by the Global Warming Solutions Act of 2006 (Division 22.5 [beginning with Section 38500] of the Health and Safety Code). Eligibility for a combustion-operated distributed generation projects using fossil fuels requires a 60 percent minimum efficiency requirement and a NO_x emissions limit of 0.07 lb/MWh.

ARB's GHG Mandatory Reporting Regulation applies to cogeneration CHP facilities above a certain size and GHG emission level, and to general stationary combustion facilities.[3]

The Federal Energy Regulatory Commission (FERC) administers Title 18, Part 292 of the Code of Federal Regulations (CFR), under Sections 201 and 210 of the Public Utility Regulatory Policies Act of 1978 (PURPA) regarding small power production and cogeneration. Part 292 reflects a 30-year history of federal proceedings relating to the

2. *Cost Benefit Analysis of the Self-Generation Incentive Program.* October 2008. Energy Commission Report. CEC-300-2008-010-F.

3. Figure 12.1 Stationary Combustion and Cogeneration Reporting Applicability in Mandatory Reporting of Greenhouse Gas Emissions Instructional Guidance for Operators, December 2008.

operation of CHP systems and their relationship to sales of export electricity to electric utilities.

The Association of State Energy Research and Technology Transfer Institutions (ASERTTI), with funding primarily from the U.S. Department of Energy, the Energy Commission, and the New York State Energy Research and Development Authority (NYSERDA), has developed a set of distributed generation (DG) system performance testing and reporting protocols. The protocols address the performance of microturbine generators (MTG), reciprocating engine generator sets including Stirling cycle, small turbines, and fuel cell power systems, and are applicable to systems with and without CHP. Application of the protocols will provide uniform data of known quality obtained in a consistent manner for all systems evaluated.

The four parallel protocols are:

- The Laboratory Protocol was developed by the Gas Technology Institute and the Program Steering Committee to provide data on performance within a controlled laboratory setting.
- The Field Protocol provides detailed data for a short-term period on the electrical, thermal (if applicable), emissions, and operational performance of commercial DG systems in a field setting. The field protocol was developed by the Southern Research Institute.
- The Case Study Protocol uses data collected from the Long-Term Monitoring Protocol as well as additional financial and qualitative information providing an assessment of a commercial application. This protocol was developed by the University of Illinois-Chicago, Energy Resources Center.
- The Long-Term Monitoring Protocol is used for continuous testing at commercial sites for a limited set of parameters. The protocol was developed by the Connected Energy Corporation and is the most relevant for implementing the act.

The performance results of DG systems tested and/or monitored with the protocols are available in a public searchable database at www.dgdata.org managed by the National Renewable Energy Laboratory (NREL). In addition, data from New York CHP systems using the Long-Term Monitoring Protocol are available at a related website at http://chp.nyserda.org.

The ASERTTI-developed protocols relied on a large body of standards published by organizations such as the Association of Mechanical Engineers (ASME). The Southern Research Institute (SRI) operates the Greenhouse Gas Technology Center under a cooperative agreement with the U.S. Environmental Protection Agency. SRI has prepared Test and Quality Assurance Plans for CHP systems. The plans and results of testing are available at www.sri-rtp.com/power_production.htm. The test plans include descriptions of instruments used, instrument accuracy, instrument location within the CHP system and within the thermal host facility, and physical parameters that are measured. SRI was one of the organizations involved in preparing the ASERTTI Performance Testing and Reporting Protocols.

EUROHEAT and POWER, the international association for CHP, has developed guidelines for quantifying CHP system inputs and outputs. The guidelines do not include quality rankings such as fuel savings or environmental impact. The guidelines have been published by the European Committee for Standardization (CEN) as *Manual for Calculating Combined Heat and Power*. The manual is especially thorough in describing how to draw the CHP system boundary and in identifying locations for meters.

Except for the *SGIP Handbook* and the FERC regulations, the sources cited do not set CHP system performance requirements. The rationales for selecting specific CHP system performance and reporting requirements are provided in Chapter 4.

CHAPTER 4: Qualifying CHP System Performance and Reporting Requirements

Net Electrical Generating Capacity Limit of 20 MW

Recommended Requirement

The 20 MW limit is applied to the net generating capacity determined as the nameplate electrical rating, as specified by the prime mover/generator manufacturer(s), at 100 percent output and under continuous operation and standard operating conditions minus parasitic electrical loads needed to operate the prime mover and the generator. Standard operating conditions of temperature, relative humidity, and elevation are specified by the International Organization for Standardization (ISO).

Legislative Requirement Satisfied

Section 28402 (b) – "Eligible customer-generator" means a customer of an electrical corporation that uses a combined heat and power system with a generating capacity of not more than 20 megawatts.

Rationale

The U.S. Energy Information Administration's Energy Glossary defines generator nameplate capacity as the maximum rated output of a generator under specific conditions designated by the manufacturer. Generator nameplate capacity is usually indicated in units of kilovolt-amperes (kVA) and in kilowatts (kW) on a nameplate physically attached to the generator. The Energy Glossary also defines the term *generator capacity* as the maximum output that generating equipment can supply to system load, adjusted for ambient conditions.

The generator nameplate capacity under ISO conditions is a unique number that can be verified through the generator manufacturer. The guidelines allow for the subtraction of parasitic loads needed to operate the prime mover (i.e., drive system) and the generator in recognition of the facts that the prime mover is an integral part of the CHP system and that different prime movers have different parasitic loads to operate auxiliary equipment. The correction for these parasitic loads puts prime movers on a common basis.

The guidelines do not allow corrections for site conditions that affect prime mover output, for two reasons. First, the definition of how output capacity is determined is critical only at or near the 20 MW level. Second, the guidelines would need to specify the capacity correction factors which, in practice, may never be needed for certification.

Topping Cycle Thermal Energy Output Limit

Recommended Requirement

The thermal energy output of a topping cycle CHP system,[4] as designed, shall be no larger than the maximum one-hour thermal load served by the CHP system as useful thermal energy.

Legislative Requirement Satisfied

Section 2840.2 (a) – "Combined heat and power system" means a system that is sized to meet the eligible customer generator's onsite thermal demand.

Rationale

Section 2843 (a) states that the guidelines shall assure that a qualifying CHP system shall: (1) reduce waste energy; be sized to meet the eligible customer-generator's thermal load; and (3) operate continuously in a manner that meets the expected thermal load and optimizes the efficient use of waste heat.

The CHP system design process includes a compilation of electrical and thermal loads of the host facility. In general, the electrical and thermal loads vary daily, weekly, and seasonally and do not track each other at a constant ratio. The thermal-to-electric ratio varies for prime movers and is a factor in determining which prime mover is most appropriate, or most closely matches the loads, for a given application.

If a CHP system operator does not have the option of exporting excess electricity, the CHP system's generating capacity must be chosen to be no larger than the on-site electrical load. The act lessens this design constraint such that the CHP system can be designed to meet the thermal load in the most efficient and economical manner.

Some participants to this proceeding have suggested that the 20 MW size limit coupled with the "operate continuously" requirement means that the CHP system should be sized to meet

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4. Topping Cycle CHP System: A CHP system in which the input energy (for example, fuel) is used first for electricity production and at least some of the reject heat from electricity production is then used as useful thermal energy.

the minimum thermal load. They contend that oversizing a system will make the CHP system operation inefficient and/or require that thermal energy be dumped at times of low thermal demand. This contention ignores the additional language that the CHP system should both meet the expected thermal load and optimize the efficient use of waste heat. Limiting the CHP system's thermal output to the minimum thermal load improperly constrains the optimization process. This contention also implicitly assumes that CHP system design engineers will not consider the impact of CHP system oversizing on economic return.

The guidelines' performance and monitoring requirements define an envelope in which CHP systems must be designed and operated. If thermal energy is dumped because the CHP system was not designed to follow thermal load, the energy output efficiency will decrease and could fall below the efficiency standard. Sizing a CHP system to the minimum thermal load or to any thermal load point less than the maximum thermal load could require either the installation of another CHP system that does not export electricity or a boiler/furnace/process heater. A design and performance criterion that could force an owner/operator to provide redundancy would be incompatible with the act's intent to encourage CHP and to do so in an economically feasible manner.

Energy Conversion Efficiency Standard

Recommended Requirement

A topping cycle CHP system shall achieve an energy conversion efficiency of no less than 62 percent both as designed and on an annual operating basis. The Energy Conversion Efficiency shall be calculated by dividing the useful energy output of the CHP system by the fuel energy input on a high heating value (HHV) basis.

A bottoming cycle CHP system that uses supplementary firing shall achieve an energy conversion efficiency of no less than 60 percent both as designed and on an annual operating basis. The energy conversion efficiency shall be calculated as the useful energy output occurring downstream of the supplementary burner divided by the supplementary firing fuel energy input on a HHV basis.

A bottoming cycle CHP system that does not use supplementary firing is exempt from the Energy Conversion Efficiency Standard.

Legislative Requirement Satisfied

Section 2843 (e) (1) An eligible customer-generator's combined heat and power system shall meet an oxides of nitrogen (NO_x) standard of 0.07 pounds per megawatt hour and a minimum efficiency of 60 percent. A minimum efficiency of 60 percent shall be measured as useful energy output divided by fuel energy input. The efficiency determination shall be based on 100 percent load.

Rationale

Section 2840.6 (a) states, "It is the intent of the Legislature that state policies dramatically advance the efficiency of the state's use of natural gas by capturing unused waste heat, and in so doing, help offset the growing crisis in electricity supply and transmission congestion in the state."

Although simple in concept, developing an efficiency standard requires consideration of multiple technical factors because the act has a quantitative efficiency requirement (minimum 60 percent at 100 percent load) and qualitative requirements (optimizing efficient use of waste heat, technological feasibility, sizing to meet thermal load, and greenhouse gas emissions reduction) that affect a CHP system's efficiency. This section addresses the quantitative aspects first, then the qualitative requirements.

Fuel Energy Input

Fuel energy per unit mass or unit volume is specified by the heat content or heat of combustion. Heat of combustion is determined under well-defined conditions and is specified for its higher heating value (HHV) and/or its lower heating value (LHV). The choice of LHV or HHV in requiring a minimum 60 percent efficiency is significant because the LHV and the HHV of a given fuel can differ by approximately 10 percent. The act does not specify which heating value is to be used.

Using a 60 percent efficiency on a HHV basis occurs in California legislation governing the SGIP. Assembly Bill 1685 (Leno, Chapter 894, Statutes of 2003) defined clean and ultra-clean distributed generation (DG) and set a ≥ 60 percent HHV efficiency requirement for CHP. AB 2778 limited the SGIP to fuel cells and wind from January 1, 2008 to January 1, 2012, and set efficiency requirements for CHP (≥ 60 percent HHV) and electric only DG (≥ 40 percent HHV). Although the act does not specify HHV or LHV, the specification of HHV for another program that provided incentives for CHP installations suggests that HHV was intended in the act.

The choice of LHV or HHV in setting a performance requirement is important because the LHV of any fuel containing hydrogen is smaller (lower) than the HHV:

- Methane HHV = ~23,900 Btu/lb; LHV = ~21,580 Btu/lb
- Natural Gas HHV = ~23,000 Btu/lb; LHV = ~19,500 Btu/lb

In the CHP system efficiency calculation, the fuel's heating value is in the denominator. Therefore a 60 percent HHV efficiency requirement is approximately a 66-67 percent LHV efficiency requirement for natural gas as the fuel. HHV is used by electric utilities in reporting the efficiency and heat rate of power plants. Manufacturers of turbines and engines report efficiency on a LHV basis because the heat of vaporization of water typically is not recovered from the exhaust stream. Condensing the exhaust results in the accumulation of acid gases, which are corrosive to commonly used exhaust system metallic components.

Useful Energy Output

This section discusses both the forms of energy that constitute "energy output" and the definition of "useful."

The act clearly includes electricity and thermal energy as output energy forms. The guidelines add mechanical shaft energy. The inclusion of mechanical energy follows FERC regulations and is consistent with energy conversion processes. Heat engines convert chemical energy to heat and then to mechanical energy. An electrical generator is required to convert the mechanical energy to electrical energy. The use of mechanical energy directly, for example, to turn a pump shaft, would be more efficient than the chemical energy to mechanical energy to electrical energy to mechanical energy process.

FERC includes chemical energy as a form of output energy. Useful chemical output could occur, for example, in a fuel cell system that reformed fuel to produce hydrogen, a portion of which was diverted for other than fueling the fuel cell. The reforming process can be categorized as the useful use of thermal energy and can be included in the useful energy output on that basis.

FERC ruled under its Fundamental Use Test that the electrical, thermal, chemical, and mechanical output of new qualifying cogeneration is used fundamentally for industrial, commercial, residential, or institutional purposes and is not intended fundamentally for sale to an electric utility if at least 50 percent of the aggregate annual output is used fundamentally for industry, commercial, residential, or institutional purposes (a safe harbor provision). The guidelines do not impose a Fundamental Use Test because the sale of electricity is a contractual issue associated with the CPUC tariff.

The definition of and the determination of "useful" are especially important for thermal energy because accounting for thermal energy requires the measurement of mass flows and temperatures in hot water lines, steam lines, make-up water, and exhaust streams.

Section 292.202 (g) of Title 18 of the CFR defines useful thermal energy output of a topping cycle CHP system as made available to an industrial or commercial process (net of any heat contained in condensate return and/or makeup water). "Made available" is an ambiguous test in that it does not place any limits on how well the thermal energy is used.

FERC made changes to PURPA in 2006. On February 2, 2006, FERC issued Order No. 671 under to section 1253 of the Energy Policy Act of 2005 (EPAct 2005) and section 210 of the PURPA to implement amended regulations governing cogeneration and small power production facilities. EPAct 2005 required that FERC issue a rule that: (1) ensures that new qualifying cogeneration facilities are using their thermal output in a productive and beneficial manner; (2) the electrical, thermal, chemical, and mechanical output of new qualifying cogeneration is used fundamentally for industrial, commercial, residential, or institutional purposes; and (3) there is continuing progress in the development of efficient electric generating technology.

Section 292.205 (d) (1) of Title 18 of the CFT requires that the thermal output be used in a productive and beneficial manner. Order No. 671 contains a discussion of Comments and the Commission Determination on what is productive and beneficial. FERC declined "to institute a bright line or specific standards concerning what constitutes acceptable thermal output." Instead FERC said it "will consider factors such as whether the product produced by the thermal energy is needed and whether there is a market for the product." FERC put the burden on the applicant to demonstrate compliance with this requirement. However, FERC adopted a rebuttable presumption that CHP systems 5 MW and smaller meet the productive and beneficial requirement based on its experience with small CHP facilities. Compliance with FERC requirements for status as a qualifying facility is shown via the submittal of FERC Form No. 556, 18 CFR Section 131.90, Certification of Qualifying Facility Status for an Existing or a Proposed Small Power Production and Cogeneration Facility.

The guidelines require that the applicant for CHP system certification show that the thermal output is used in a productive and beneficial manner based on CHP system design, facility process equipment thermal requirements and operation, and engineering analysis under two operating conditions: (1) at 100 percent output of the prime mover (an operating condition specified in the act; and (2) under "average annual hourly operating conditions," a concept contained in FERC regulations and introduced into the guidelines, to obtain designation as a "certified CHP system."

FERC addressed the issue of continuing compliance and took the position that once certified the qualifying facility may continue to rely on the initial determination, "absent a change in the operations of the facility," and stated that a purchaser of the electrical output may not return to FERC to allege that the thermal output is not productive and beneficial.

The guidelines are more stringent than FERC on the continued satisfaction of the "productive and beneficial" requirement for the thermal energy output. For the purposes of the act, a tariff-eligible CHP system must meet the useful thermal output requirement during every calendar year of operation. This would be shown by monitoring and reporting monthly energy flows to and from the CHP system, between the CHP system and the host facility, and within the host facility.

In summary, with respect to thermal energy output, the guidelines are consistent with FERC on the use of thermal energy output in a productive and useful manner and are more stringent than FERC in requiring that satisfaction of the thermal energy requirement be demonstrated every calendar and not just in the initial application for certification.

Selecting an Efficiency Metric

As noted above, 60 percent minimum efficiency level has been set for participation in the SGIP, and the act contains other requirements that can be satisfied by an efficiency standard.

This section discusses whether a level above 60 percent should be set, whether the same efficiency standard should apply to bottoming cycles and topping cycles, whether the standard should apply at other than full load (that is, over some operational range), and whether different or additional efficiency measures should be used.

The relative efficiencies of boilers and power plants is an indicator of the relative value of electrical energy output and thermal energy output from separate processes; one that produces steam only and one that produces electricity only (although frequently with an intermediate thermal energy conversion process). Compare the efficiency of a boiler to that of an electricity generating plant. The rated efficiency of a modern boiler is approximately 80 percent. The efficiencies of utility-scale electricity generating plants range from approximately 35 percent to somewhat less than 50 percent. For simplicity and for illustration only, assume an electrical generating efficiency of 40 percent. That is, under one commonly used efficiency metric, a boiler is twice as efficient as an electricity generating plant.

However, electricity has a greater ability to do work than hot water or steam from a boiler. One MWh of electricity can be converted to 3.412 million British thermal units (MMBtu) of hot water via resistive heating, as an approximation. But 3.412 MMBtu of steam can be converted to only 0.3 MWh of electricity in a Rankine cycle power plant. Electricity has the premium ability to do work. This ability to do work comes at the expense of more fuel energy required to produce a unit of electrical energy output.

Keith Davidson of DE Solutions, Inc., presented a method at the October 26, 2009, workshop on the act implementation for determining the "Fuel Chargeable to Power" in a CHP system. The methodology recognizes that there is no choice on consuming fuel for thermal needs. The fuel chargeable to power is the total fuel to the CHP system minus the avoided boiler fuel. The net fuel heat rate is the ratio of the fuel chargeable to power divided by the electrical energy generated. Net fuel heat rates on the order of 6,000 Btu/kWh were calculated assuming 80 to 85 percent displaced boiler efficiencies. The calculation is simple but it requires a judgment on an acceptable net heat rate, comparable to the judgment required for the double benchmark and fuel savings methodologies.

The U.S. Environmental Protection Agency lists various methods for expressing and calculating CHP system efficiency in its *Catalog of CHP Technologies* (December 2008), available at [http://www.epa.gov/CHP/documents/catalog_chptech_full.pdf]. One of these is the Percent Fuel Savings, which compares the fuel used by the CHP system to the separate generation of electricity and thermal energy. The method involves a double-benchmarking technique wherein the efficiencies of the grid-supplied electricity and boiler-provided thermal energy are specified. Mathematically the fuel savings percentage can be expressed as:

$$\text{Fuel Savings} = 1 - \{F_{ave} / [P_{ave}/Eff_P + M_{ave}/Eff_M + Q_{ave}/Eff_Q]\}$$

- F_{ave} is the fuel energy input to the CHP system

- P_{ave} is the useful net electrical energy output
- M_{ave} is the useful mechanical energy output
- Q_{ave} is the useful thermal energy output
- Eff_P is the efficiency of the displaced grid electricity system
- Eff_M is the efficiency of a mechanical drive
- Eff_Q is the efficiency of "displaced" thermal generation

The energy values must be in the same unit and the energy input and outputs must be determined over the same period. One advantage of the Fuel Savings metric is that the GHG savings is simply the product of the fuel savings percentage, the fuel energy input, and the carbon dioxide emission factor, which in the *ARB GHG Scoping Plan* has a default value of 117 lb CO_2/MMBtu.

Ray Williams of Pacific Gas &Electric (PG&E), in testimony presented before the October 12, 2009, E & NG Committee Workshop, Combined Heat and Power Guidelines, and PG&E in written comments submitted on October 26, 2009, to Docket 08-WHCE-1, proposed a double benchmark for the efficiency of separate heat and power systems, the same as those used in the Fuel Savings Calculation; compared various efficiency metrics as a function of the power-to-heat ratio; and proposed a simplification of the Energy Commission Staff Draft Guidelines relating to efficiency, fuel savings, and GHG emissions reductions. The PG&E comments provide insights into the interaction between and usefulness of various efficiency metrics. PG&E's policy position can be summarized as stating that the guidelines should ensure that every CHP system that obtains a contract under the act reduces GHG emissions.

PG&E comments on the Committee Final Guidelines submitted to the docket on January 15, 2010, elaborated on its earlier comments and stated that "a carbon-neutral double benchmark is the appropriate way to determine whether a CHP installation decreases GHG emissions. PG&E proposes an electric system efficiency of 47.3 percent and a boiler efficiency of 80 percent. PG&E states that the double benchmark "underlies the CHP Program Measure developed by the ARB in the AB 32 Scoping Plan" and "is widely acknowledged as the proper method for assessing the GHG impact of CHP."

Both the fuel savings metric and the double benchmark concept require the specification of the efficiencies of the displaced grid electricity system and the displaced boiler. Two associations, Euroheat & Power and COGEN Europe, in a statement dated May 3, 2004, discussed the selection of these values to "support the development of CHP in Europe and determine the benefits in a balanced and fair manner." They state that the values of the double benchmark must be based on operational data from power plants and boilers that have been operating for one complete year, including all system losses, cycle losses, and maintenance, should be for the same year of operation or investment as the CHP system, should consider the grade of heat, and should reflect a load range similar to that of the CHP system. The comments were made to address the definition of Europe–wide harmonized reference values for cogeneration under the EU Cogeneration Directive adopted in February 2004.

PG&E proposed a higher efficiency value for the displaced generation (47.3 percent) than was used in the *AB 32 Scoping Plan* (42 percent). Southern California Edison (SCE), in comments dated December 21, 2009, restated its support for the Fuel Savings Standard and cited a range for the displaced generation (about 42 percent to 47 percent) and the displaced boiler (about 80 percent to 85 percent). SCE and Joseph Stanger, Executive Director – Sustainability and Energy Management at Stanford University, but testifying as a private citizen, both encouraged the Energy Commission to evaluate appropriate values for the Double Benchmark.

Staff and stakeholders could not arrive at a consensus on either the displaced power plant heat rate or efficiency (proposed values are between 40 and 50 percent) or the losses in the transmission and distribution system (ranging from zero to 8 percent on average, and above 10 percent at times of system peak). Further discussion of the Double Benchmark is given in the Greenhouse Gas Mitigation Section.

PG&E plotted various efficiency metrics as a function of power-to-heat ratio. "Power" in this usage is the colloquial word for electrical energy. PG&E's graphical presentation shows the P/H ratios at which either the Fuel Savings Standard or a uniform total output energy efficiency standard is the more stringent standard. The presentation also shows that the Guidelines can be simplified by adopting only a total output energy efficiency standard. The fuel savings standard is more stringent than the total output energy efficiency standard only at extremes of low power-to-heat ratios (when P/H is less than 0.5 and the boiler efficiency benchmark becomes the controlling efficiency value) and high power-to-heat ratio (when P/H is greater than 3.0 and a 15 percent minimum thermal requirement used in FERC regulations, [discussed subsequently,] becomes controlling). CHP systems with P/H ratios below 0.5 will probably have little electricity export after satisfying on-site electrical needs. For the other extreme in the P/H ratio, PG&E notes that high P/H ratios "are not contemplated by the act."

The above considerations suggest that only one efficiency metric, the Energy Conversion Efficiency, is needed. The following paragraphs discuss the selection of the total energy output efficiency value.

Setting the Minimum Total Output Energy Efficiency Value.

Don Schoenbeck, representing the Energy Producers and Users Coalition and the Cogeneration Association of California, compared efficiencies of CHP systems on the SCE system to central station generation power plant efficiencies at the April 13, 2009, workshop. The average CHP fleet efficiency was cited as 65 percent, a value confirmed by SCE. The range is below 40 percent to almost 90 percent, and the median efficiency value is below 60 percent. According to SCE, the CHP system efficiencies are independent of size.

The draft CHP market assessment study cited in the 2009 IEPR proceeding and in the final report *Combined Heat and Power Market Assessment – Final Consultant Report*[5] can guide the selection of this efficiency value. Table 43 of the ICF International Report provides "effective CHP efficiencies" for those CHP systems that are forecast to be installed under five scenarios. These effective CHP efficiencies reflect a mix of the prime mover technologies that were assumed to be available for installation over time. The detailed cost and performance characteristics of each candidate technology are provided also. For a candidate technology to enter the mix of technologies that penetrate the market, it must be found to be cost-effective. For technologies that are smaller than 20 MW, within the scope of the act, the effective CHP efficiencies for the mix of technologies that are forecast to enter the market are between 62.3 and 62.8 percent.

The act gives equal weighting to electrical and thermal energy in calculating useful energy output. With this equal weighting of electrical and thermal energy, and under the definition of and reporting requirements for useful energy output, the total useful energy output value depends significantly on the percentage of the thermal energy that is used. At 100 percent thermal utilization, the ICF International prototype CHP systems have efficiencies between 59 percent and 79 percent. Across all candidate new CHP installations, an 80 percent thermal utilization assumption is more realistic than a 100 percent thermal utilization assumption. At 80 percent thermal energy utilization, the prototype CHP systems have useful energy output efficiencies between 58 percent and 74 percent.

FERC regulations discount the value of thermal energy by 50 percent, an arbitrary but reasonable approach under thermodynamic considerations on the ability of different energy forms to do work, as was noted previously in the comparison of boilers and electricity generating plants. The FERC operating and efficiency standards for topping cycle qualifying cogeneration facilities are

- The useful thermal energy output must be no less than 5 percent of the total energy output on an annual basis.
- The useful power output plus one-half of the thermal output must be no less than:
    - 42.5 percent of the total fuel energy input on an annual basis, or
    - 45 percent of the total fuel energy input on an annual basis, if the useful thermal energy output is less than 15 percent of the total energy output.

5. CEC-500-2009-094-F, published April 2010.

For any bottoming cycle[6] cogeneration facility using supplementary firing, the useful power output must be no less than 45 percent of the energy input of natural gas and oil for supplementary firing.

Fuel energy input is determined on a lower heating value basis. (18 CFR Section 292.205)

The act specifies different conventions for calculating the energy output efficiency than those adopted by FERC. Mathematical manipulation is required to compare the two sets of standards using common conventions.

The guidelines use higher heating value (HHV) rather than lower heating value (LHV) for fuel input. The ratio HHV/LHV for methane is 1.11. The ratio HHV/LHV for natural gas depends on the percentages of methane and higher hydrocarbons in the mix. The ratio for natural gas delivered to California is approximately 1.18. For a given mass of fuel energy input and the consequent energy output, the efficiency of a given CHP system is higher if expressed as LHV than if expressed as HHV. Stated another way, a specific numerical efficiency standard value (for example, 62 percent) requires more useful energy output when expressed as HHV than when expressed as LHV.

FERC's topping cycle CHP system efficiency standard is:

- $42.5\% = (E + ½ T) / F_L$, where F_L is the fuel energy input on a LHV basis

On a HHV basis, the FERC efficiency standard can be written as:

- $0.425\ F_L / 1.18 = 0.360\ F_H = E + ½ T$

Or:

- $0.45\ F_L / 1.18 = 0.381\ F_H = E + ½ T$, when thermal output is below 15 percent of total

The guidelines standard for topping cycle CHP systems is:

- $0.62\ F_H = E + T$

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6. Bottoming Cycle CHP System: A CHP system in which the input energy (for example, fuel) is used first to produce useful thermal energy for a process and the residual thermal energy is then used for electricity production.

The FERC energy efficiency standards can be compared to those in the act at two extreme P/H ratios of zero and infinity. Neither of these extremes represents a system that produces both thermal energy and electricity; CHP systems lie between these extremes.

At P = 0, P/H = 0 (all thermal, a boiler or process heater):

- Output Energy = T = 0.62 / F_H under the Guidelines
- Output Energy = T = 0.72 / F_H under FERC

At T = 0, P/H = infinity (an electricity only generator):

- Output Energy = E = 0.62 / F_H under the Guidelines
- Output Energy = E = 0.38 / F_H under FERC

The ratio (E + T) / F_H varies with P/H under FERC but is constant under the guidelines.

A 62 percent total energy output efficiency standard is more stringent than the FERC efficiency standard except when the electrical output of the CHP system is low (the P/H ratio is less than 0.19), a region that CHP systems under the act are unlikely to fall in because they are selling excess electricity.

A 62 percent total energy output efficiency standard bars "PURPA machines," for example, CHP systems that are primarily electricity generators but use some thermal energy to take economic advantage of preferences given to CHP systems.

A 62 percent total energy output efficiency standard is more stringent than FERC's 45 percent total energy output standard when the thermal energy output is less than 15 percent of the total energy output or when the P/H ratio is greater than 5.33. Technologically feasible CHP systems that are not larger than 20 MW cannot achieve a 62 percent total output energy efficiency level unless they have a thermal energy output greater than 15 percent. Therefore, the guidelines do not need to contain the 15 percent thermal energy output requirement that is contained in FERC regulations.

A 62 percent efficiency standard is a technologically achievable and economically feasible minimum efficiency level for topping cycle CHP systems. This is above the minimum efficiency requirement in the act and above the median efficiency of CHP systems connected to the SCE system.

Bottoming Cycle CHP Systems That Do Not Use Supplementary Firing

Bottoming cycles typically are applied in industrial applications that require high processing temperatures, such as calcining and melting. Even when the industrial facility is efficiently designed and operated so as to lower the temperature of the exhaust for preheating materials and process water, the waste heat exhausted to the environment may still be at a temperature of a few hundred degrees. This waste heat can be converted to steam in a heat recovery boiler and then to electricity by a steam turbine operating in a Rankine cycle.

For a bottoming cycle CHP system without supplementary firing, fuel is consumed to satisfy thermal loads that exist whether or not a CHP system is present. The CHP system captures the waste heat that would otherwise be dumped to the environment. The fuel chargeable to power is zero, and the net fuel heat rate is zero. This implies infinite electrical generation efficiency because the output energy is divided by zero in the efficiency calculation. In recognition of this situation, both FERC and the guidelines exempt bottoming cycle CHP systems without supplementary firing from an energy output efficiency standard.

Bottoming Cycle CHP Systems That Use Supplementary Firing

The waste heat from an industrial process may not be hot enough to generate electricity economically. The economics and environmental benefits of waste heat recovery can be improved by burning fuel to raise the temperature of the exhaust stream going to a heat recovery steam generator and then to a steam turbine. This is called supplementary firing.

With supplementary firing, fuel is being consumed to increase the amount of electricity that can be generated from the waste heat recovery alone. Therefore, an efficiency standard is required for a bottoming cycle that uses supplementary firing. The act sets a minimum efficiency level of 60 percent. The guidelines raise the efficiency standard to 62 percent for a topping cycle. For consistency, the efficiency standard for a bottoming cycle could be set at 62 percent also. However, a difference in the efficiency standard for a bottoming cycle CHP system from that of a topping cycle CHP system is justified by two factors. First, a bottoming cycle CHP system captures and uses exhaust heat from an industrial process that typically is dumped into the environment, whereas a topping cycle captures the waste heat from an electricity generator's exhaust, just as a boiler or process heater would consume fuel to provide the thermal load. Second, there is a fundamental difference in the quality of the energy products produced by top and bottom cycling systems. Specifically, a bottoming cycle CHP system produces electrical energy and mechanical energy exclusively or predominantly. A topping cycle system produces a mix of electrical, mechanical, and thermal energy, and electrical energy has higher value than thermal energy.

The Coalition for Sustainable Cement Manufacturing & Environment (Coalition) filed testimony to the docket on March 25, 2010, arguing that at having a 60 percent efficiency level for a bottoming cycle CHP system is significantly more efficient than and has significantly lower GHG emissions than a specific new natural gas-fired power plant. Calculations that the coalition submitted show GHG emissions of 666 lbs. of CO_2 per MWh at a 60 percent efficiency level compared to 825 lb/MWh for the Russell City Energy Center in Hayward, California.

The coalition's testimony provides a policy basis for favoring a 60 percent efficiency standard over a 62 percent efficiency standard for bottoming cycle CHP systems. As the efficiency requirement increases, the amount of supplementary firing that can be employed decreases. As an approximation, an increase from 60 percent to 62 percent, or a change of 3+ percent, results in a decrease in the quantity of supplementary fuel that can be used and a 3+ percent decrease in the bottoming cycle CHP system electrical output. The more detailed calculations by the coalition confirm the results of this simplified analysis.

The reduced electricity generation under a 62 percent efficiency standard as compared to the electricity generation at a 60 percent efficiency standard is a perverse outcome: at either 60 percent or 62 percent, a bottoming cycle CHP with supplementary firing is the most efficient natural gas fired electricity generator in the state. At 62 percent efficiency, GHG emissions are lower, but so are the installed generating capacity and the electrical energy produced. A 60 percent efficiency standard is more consistent with both the act and AB 32 goals than a 62 percent efficiency standard for bottoming cycles with supplementary firing.

CHP System Boundary and Thermal Host Facility Boundary

The performance protocols cited earlier require that all CHP system equipment and all electrical and thermal utilization equipment be separated into one of two regions enclosed by a boundary. Without the clear definition of a boundary and a tabulation of all relevant mass and energy flows, the efficiency cannot be defined and determined.

The applicant and the owner/operator are required to provide drawings and descriptions of the CHP system and thermal host facility diagrams. References cited previously contain guidance for setting the boundaries.

Environmentally Beneficial, Especially With Respect to Greenhouse Gas Emissions

Recommended Requirement

An efficiency of 62 percent for a topping cycle CHP system corresponds to 650 lbs CO_2/MWh, well below the 1,100 lb/MWh requirement in the act. The direct linkage between efficiency, fuel savings, and carbon dioxide emissions means that specifying any one specifies the other two, for a given fuel.

On June 22, 2009, the CPUC issued Decision 09-06-051 in proceeding R 06- 04-009 to Implement the Procurement Incentive Framework and to Examine the Integration of Greenhouse Gas Emissions Standards into Procurement Policies. Under the decision, only GHG emissions associated with any supplementary firing would be considered in calculating the environmental performance standard (EPS) for bottoming cycle CHP systems. The guidelines are consistent with the CPUC decision.

Legislative Requirement Satisfied

According to the Act, the CHP system shall comply with GHG performance standard pursuant to Public Utilities Code Section 8341. Section 8341 codifies Senate Bill 1368 (Perata, Chapter 598, Statutes of 2006). The law limits long-term investments in baseload generation by the state's utilities to power plants that meet an emissions performance standard (EPS) jointly established by the Energy Commission and the CPUC. Energy Commission regulations establish a standard for baseload generation owned by, or under long-term contract to publicly owned utilities, of 1,100 lbs (or 0.55 ton) CO_2 per MWh. The implied heat rate is approximately 9,400 Btu/kWh. According to the Energy Commission staff report on SB 1368 implementation, the 1,100 lb/MWh emissions level is the midpoint of the emissions of natural gas power plants in the Western Electricity Coordinating Council (WECC).

The act requires both the achievement of an emissions performance standard and “significant reductions” in greenhouse gas emissions.

Under the act, the ARB is responsible for reporting GHG emissions reductions associated with the installation of CHP systems qualifying for the tariff provided for in the act. Under AB 32, the ARB has adopted a Regulation for the Mandatory Reporting of Greenhouse Gas Emissions and has published *Instructional Guidance for Operators*. CHP systems with a capacity of 1 MW and above and emitting 2,500 MT/year (2,500,000 kg) or more of CO_2 from electricity generating activities are subject to reporting.

Rationale

Most CHP systems are fueled by natural gas. The most important GHGs are carbon dioxide and methane, with methane being a more potent GHG. CHP system efficiency and carbon dioxide emissions are directly linked. Reductions in carbon dioxide in CHP systems come directly from the higher efficiency in converting fuel energy to the sequential production of electricity and usable heat compared to the separate central station generation of electricity from natural gas and the on-site production of thermal energy. Additional CHP savings come from the elimination of line losses in getting central station-generated electricity to the end user.

The issue of “significant reductions” is more complicated. The level of GHG emissions reduction depends both on the characteristics of the CHP system and the emissions of the separate electricity generation and thermal production that the CHP system displaces. Different levels of GHG emissions reduction can be calculated by making different assumptions about the utility generation power plant or generation mix and the on-site boiler, furnace, and/or electric chiller that are being displaced. The choice of the displaced electricity generation is especially contentious, both on a scientific level and on a policy level, for evaluating end-use energy efficiency programs, renewable portfolio standard benefits, and AB 32 implementation success, among others.

Two basic approaches have been used to specify the displaced power plant. One approach uses the existing fleet of power plants. The other approach uses the generation plant or generation mix that would not be built because of CHP system installations.

The existing fleet can be taken variously as the generation mix within a service territory, within California; the California supply mix; the mix within the WECC, natural gas-fired generation only; dispatchable natural gas-fired generation; historical emissions from the selected mix; forecast emissions within the selected mix; one-year emissions; multiple-year average emissions; moving average emissions; etc. The difficulty of defining the displaced generation was discussed previously under the Energy Conversion Efficiency discussion.

The characteristics of the existing fleet have been used in two evaluations of the SGIP. Itron, Inc, as a contractor to the SGIP administrators, has adopted procedures for calculating GHG emissions and has applied these procedures to installed CHP systems.[7] Hourly CO_2 emission factors were based on a method initially developed by Energy and Environmental Economics for the CPUC using a mix of utility generation resources that could be subject to hourly dispatch.

TIAX LLC, in its *Cost Benefit Analysis of the Self-Generation Incentive Program Report* to the Energy Commission, used a simpler approach to specify the non-CHP options. TIAX chose a natural gas combined cycle (NGCC) power plant as the electricity generation system displaced and an 85 percent efficient boiler as the thermal system displaced. Both studies came to the same conclusion: small GHG reduction impacts from the SGIP systems.

None of the cited analyses have recognized that CHP is fundamentally a boiler replacement measure rather than an electricity generation measure. Little attention has been given to the nature of the displaced boiler. Recommendations from stakeholders assume that the displaced boiler is a new boiler, with efficiency between 80 and 85 percent, or perhaps above 90 percent for the most efficient boilers being demonstrated. These efficient boilers include the Super Boiler, partial funding for which has been provided by the Energy Commission's PIER Program. The operator of an existing boiler who is considering replacement could consider a new and more efficient, or perhaps super-efficient boiler, or a CHP system. Within that context, the displaced boiler is the pre-existing boiler.

A second consideration that has not been addressed is the choice that will be made for either a new power plant or a boiler, if one uses new hardware rather than existing hardware as the basis for comparison. Some stakeholders postulated that the most efficient hardware will be chosen. No evidence was presented to support this postulate.

A third consideration is the mode of operation. The guidelines require that the performance standards be met under annual operating conditions, including start up, shutdown, and part load operation under ambient conditions. The displaced hardware comparison should be made under a comparable set of operating conditions.

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7. *Seventh-Year Impact Evaluation Report*, Section 5 and Appendix B.

A fourth consideration is the size of the displaced central station resource. No qualifying CHP system can be larger than 20 MW. Central station power plants are 5 to 50 times larger. At small penetration levels, CHP systems are unlikely to defer the construction of central station power plants. A systematic investigation will be necessary to formulate an appropriate method for specifying the displaced electricity generation and the displaced thermal source.

NO_x Emissions

Recommended Requirement

The CHP system shall meet an oxides of nitrogen (NO_x) emissions rate standard of 0.07 pounds per MWh. A system meeting the efficiency standard may take a credit of 1 MWh for each 3.4 million British thermal units of heat recovered to meet the NO_x standard.

Legislative Requirement Satisfied

Section 2843 (e)

Rationale

The NO_x emission limits in the act are as strict as any previously adopted in California. The guidelines adopt the legislative requirement without change.

Other than GHGs (including N_2O), no other pollutant species are mentioned in the act. The U.S. EPA, the ARB, and local air quality management districts are responsible for regulating atmospheric emissions from stationary sources.

CHAPTER 5: Applying for CHP System Certification Recommended Requirement

Every CHP system owner/operator seeking to qualify for an export tariff under the act shall file an application with the Energy Commission consisting of the filing of a standard form (Form CEC-2843), with associated schedules and attachments. The Executive Director shall determine both the completeness of the Form CEC-2843 and demonstrated compliance with the Guidelines.

Legislative Requirement Satisfied

Sections 2841, 2842.2, 2843, 2845.

Rationale

The act establishes minimum CHP System performance standards and goals for waste heat utilization and GHG emissions reduction and gives the Energy Commission responsibility for adopting Guidelines.

The *SGIP Handbooks* describe an application process for the qualification of DG systems for that buydown program. The guidelines build on the experience with the SGIP program and require the submittal of similar information. The guidelines' Forms, Schedules and Required Attachments are different because of different legislative requirements in the two programs. The guidelines also reflect FERC's experience with the regulation of qualifying facilities.

As the record for the regulatory proceeding shows, alternatives for demonstrating compliance with the guidelines were considered, in terms of the scope, CHP system performance requirements , the demonstration of accuracy of the information, diagrams and analyses to support energy input and output estimates, and the reviewing entity and review processes.

The guidelines explicitly recognize the value of thermal energy if it is used in a productive manner for a beneficial use. The demonstration of beneficial use is especially important in showing that the CHP system will meet the total output efficiency standard.

Applicants can show that their CHP system will satisfy the performance requirements by filling out forms with contact and administrative information and energy input and output and NOx emission estimates. The supporting calculations, system diagrams, system descriptions are necessary for the Energy Commission to verify that the performance data estimates are reasonable and that the proposed CHP system will satisfy the performance requirements.

Stakeholders agreed that the Energy Commission is the appropriate entity to review the application for certification and to grant the certification for the contracts developed by the CPUC for the export and sale of electricity.

CHAPTER 6: Annual Reporting and Verification

Recommended Requirement

Each calendar year, all qualified CHP system owner/operators shall report to the Energy Commission at least once a year and on the schedule required under the ARB GHG Mandatory Reporting Regulations, on performance with respect to these Guidelines. Reporting shall be done according to an approved Testing, Reporting, Maintenance and Compliance Plan.

CHP systems that fail to meet the guideline requirements on an annual basis shall file a plan to bring the CHP system into compliance.

Legislative Requirement Satisfied

Section 2843 (g)

The act requires that an eligible customer-generator adequately maintain and service the CHP system so that it meets or exceeds the efficiency and emissions requirements.

Rationale

The guidelines go beyond the requirements in the act by requiring the annual reporting of CHP system performance as relevant to comply with the guidelines during each year of operation and electricity export. The annual reporting requirement is imposed based, in part, on California's experience with the SGIP. The SGIP subsidizes the capital cost of qualifying distributed generation equipment based on the installed capacity of the system. The SGIP does not require that system owners monitor system performance but it does require that system operators and host customers participate in measurement and evaluation activities performed by the program administrator or its independent third-party consultant. These activities include access for the installation of monitoring equipment and the collection and transfer of data. The costs for these activities are paid for by the program administrator.

The Program Administrator has performed several assessments of SGIP system performance. For example, Itron, Inc. in its *CPUC Self-Generation Incentive Program Seventh-Year (2007) Impact Evaluation*, Final Report, calculated efficiencies for CHP systems by technology for both the requirements of PUC 216.6(b) and AB 2778. Fuel cell and gas turbine-based systems met both requirements. In contrast, internal combustion engine- and microturbine generator-based systems failed both requirements. These results suggest that both the application and verification processes are necessary to assure that the act's efficiency and emission reduction goals are achieved over the life of the CHP systems.

The guidelines require that the owner/operator monitor and report on CHP system performance. Monitoring and reporting may be required by the ARB in its implementation of AB 32; therefore, the guidelines do not impose an additional monitoring or data collection burden.

The guidelines require that the owner/operator declare whether the operating CHP system met the requirements and to declare that the annual report form is accurate. The annual report form is subject to challenge, and CHP system operation is subject to audit. The audit provision ensures compliance. The Annual Reporting Forms mirror the application for certification forms.

Glossary

Acronym	Definition
AB	Assembly Bill
ARB	California Air Resources Board
ASERTTI	Association of State Energy Research and Technology Transfer Institutions
ASME	Association of Mechanical Engineers
CEN	European Committee for Standardization
CFR	Code of Federal Regulations
CHP	combined heat and power
CPUC	California Public Utilities Commission
DG	distributed generation
E&NG	electricity and natural gas
EPAct2005	Energy Policy Act of 2005
EPS	environmental performance standard
FERC	Federal Energy Regulatory Commission
GHG	greenhouse gas
HHV	higher heating value
IEPR	Integrated Energy Policy Report
IOUs	Investor Owned Utilities
ISO	International Organization for Standardization
kVA	kilovolt-amperes
kW	kilowatts
LHV	lower heating value
MMBtu	million British thermal units
MT	metric ton
MTG	microturbine generation

MW	megawatts
NGCC	natural gas combined cycle
NOx	oxides of nitrogen
NREL	National Renewable Energy Laboratory
NYSERDA	New York State Energy Research and Development Authority
OIR	Order Instituting Rulemaking
PG&E	Pacific Gas & Electric
PIER	Public Interest Energy Research
PURPA	Public Utility Regulatory Policies Act of 1978
SCE	Southern California Edison
SGIP	self-generation incentive program
SRI	Southern Research Institute
WECC	Western Electricity Coordinating Council