CALIFORNIA
ENERGY
COMMISSION

IMPLEMENTATION OF AB 1613 THE WASTE HEAT AND CARBON EMISSIONS REDUCTION ACT COMBINED HEAT AND POWER SYSTEMS

DRAFT INITIAL STATEMENT OF REASONS

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Arnold Schwarzenegger, *Governor*

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Abstract

The Waste Heat and Carbon Emission Reduction Act (Assembly Bill 1613) mandates that state policies advance the efficiency of the state's use of natural gas by using excess waste heat through the use of combined heat and power technologies. The Initial Statement of Reasons describes staff's process for developing the technical eligibility requirements for new combined heat and power (CHP) systems for incentive programs to be developed by the California Public Utilities Commission (CPUC) and publicly owned utilities, including (1) programs for the purchase of excess power generated by qualifying CHP facilities, 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.

Keywords: Carbon dioxide, carbon emission reduction, combined heat and power, combined cooling heating and power, CCHP, CHP, export tariff, fuel efficiency, greenhouse gas emissions, GHG, NO_x emissions, Self Generation Incentive Program, thermal output, waste heat recovery, waste heat utilization.

Chapter 1: Introduction

In this rulemaking proceeding, the California Energy Commission (Energy Commission) proposes to implement the Waste Heat and Carbon Emissions Reduction Act (Act), codified in Sections 2840 through 2845 of the Public Utilities Code.[1] This rulemaking process is consistent with Public Resources Code Section 25004.2, in which the Legislature stated that "cogeneration technology…should be an important element in the State's energy supply mix…which can assist meeting the state's energy needs while reducing the long-term use of conventional fuels…and reduces negative environmental impacts."

The Initial Statement of Reasons describes

- The specific purpose for each performance requirement, as contained in the Committee Proposed Guidelines for Certification of Combined Heat and Power Systems Pursuant to the Waste Heat and Carbon Emissions Reduction Act (Guidelines), mandating that a combined heat and power (CHP) system must meet these 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 facilities, 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 to maintain status as a qualifying CHP system.

The Energy Commission, the CPUC and the Air Resources Board (ARB) have responsibility for implementing various provisions of the Act. The Act contains the following specific Guidelines 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.
- 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 efficiency standard may

[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).

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 GHG emission performance standard pursuant 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 these general directives:

- The CHP system shall first commence operation on or after January 1, 2008.
- The Guidelines shall not permit de facto wholesale generators with guaranteed purchases.

The Initial Statement of Reasons includes necessary background information, to show that the Committee Proposed Guidelines address the requirements of the Act and to allow the Stakeholders to understand the Guideline development process and why specific requirements were selected.

Chapter 2: Procedural Issues

The Energy Commission instituted a Rulemaking to implement the Waste Heat and Carbon Emissions Reduction Act on December 17, 2008 with Order No. 08-1217-16. The Act requires the Energy Commission to adopt the Final Guidelines by January 1, 2010.

The California Public Utilities Commission (CPUC) opened an Order Instituting Rulemaking (OIR) R.08-06-024 on June 26, 2008, to implement the provisions of AB 1613 (AB 1613) (Blakeslee, Statutes of 2007; Public Utilities Code Chapter 8). The OIR process parallels the Energy Commission's rulemaking proceeding.

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, 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 the 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 is at [http://www.arb.ca.gov/cc/reporting/ghg-rep/ghg-rep.html].

The Electricity and Natural Gas (E&NG) Committee, the Integrated Energy Policy Report (IEPR) Committee, and the Energy Commission staff conducted three workshops and the 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, Responses to Comments posted
- October 12 – Electricity and Natural Gas Committee Workshop on CHP Guidelines, Forms, and Responses to Earlier Comments
- October 19, 2009 - Comments Due. Docket 08-WHCE-1
- November 23, 2009 - Notice of Proposed Action, Committee Guidelines, Staff's "Statement of Reasons" publicly available

- January 13, 2010 – Guidelines considered for possible adoption at Business Meeting

Chapter 3: Information Sources Used To Formulate Guidelines

Stakeholders have submitted written and oral testimony and have made suggestions at the workshops and hearings and in conversations with staff. Stakeholder comments have shaped the Guidelines during much of the year 2009.

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 (AB 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 investor-owned utilities over several years.

Assembly Bill 2778 (AB 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 greenhouse gases (GHG).[2]

Senate Bill 412 (SB 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 California 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 NOx 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—Regulations under Sections 201 and 210 of the Public Utility Regulatory Policies Act of 1978

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[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

regarding small power production and cogeneration. Part 292 reflects a 30-year history of federal proceedings relating to the 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 AB 1613.

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).

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 (CHP)*. 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 setting 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 (1) Uses a combined heat and power system with a generating capacity of not more than 20 megawatts.

Rationale

Some stakeholders have recommended that the generator nameplate rating be the basis for determining the CHP system capacity. Using the generator nameplate rating is simpler than using the net generating capacity. The distinction becomes important only for a CHP system that has a nameplate rating greater than 20 MW. In practice there may be no such CHP systems seeking certification.

Prime mover electrical power output generally will be lower than the net generating capacity at typical temperature and ambient pressure conditions in California.

Nameplate ratings are based on an assumed fuel composition, typically natural gas or diesel fuel. Achievable generating capacity may be different if operating on biofuels, waste fuels, gasified solid fuels, or mixtures and blends of fuels. The Committee Proposed Guidelines require that the Applicant calculate a fuel-specific net generating capacity if the operation on an alternative fuel would result in generating capacity exceeding the 20 MW threshold.

Topping Cycle Thermal Energy Output Limit

Recommended Requirement

The thermal energy output of a Topping Cycle CHP System, 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 (2) is sized to meet the eligible customer generator's onsite thermal demand.

Rationale

AB 1613 states that qualifying CHP system shall: (1) reduce waste energy, (2) 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. AB 1613 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 sizing requirement coupled to the "operate continuously" requirement means that the CHP system should be sized to meet the minimum thermal load. CHP systems, by definition, simultaneously provide electricity and thermal energy. If CHP systems are to be viable replacements for boilers, furnaces and heaters, the Committee Proposed Guidelines must allow CHP systems to meet the maximum one hour thermal load in a twelve month reporting period and to follow the thermal load. Sizing a CHP system to the minimum thermal load or to any thermal load point less than the maximum thermal load will require the installation of another CHP system that does not export electricity or a boiler/furnace/process heater. Forcing 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 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 input divided by fuel energy input. The efficiency determination shall be based on 100 percent load.

Rationale

Section 2840.6 (a) of AB 1613 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, the developing of an efficiency standard requires consideration of multiple technical factors because AB 1613 has a quantitative efficiency requirement (minimum 60 percent) and qualitative requirements (optimizing efficient use of waste heat, technological feasibility, sizing to meet thermal load, and greenhouse gas emissions reduction) that affect the efficiency requirement. In addition, useful energy output and fuel input must be defined in clear technical terms.

Fuel Energy Input

AB 1613 refers specifically to advancing the efficiency of natural gas use. However, nothing in the Act prohibits the use of other fuels, and other legislation encourages the use of low carbon fuels, biofuels, alternative fuels, and waste fuels. The Committee Proposed

Guidelines are intended to be neutral on the use of different and mixed fuels, specifying only the heat content or heat of combustion. Heat of combustion is specified both as a higher heating value (HHV) and a lower heating value (LHV). The choice of LHV or HHV in requiring a minimum 60 percent efficiency is significant.

Using a 60 percent efficiency on a HHV basis occurs in California legislation governing the SGIP. Assembly Bill 1685 (AB 1685) (Leno, Statutes of 2003) defined Clean and Ultra-Clean Distributed Generation (DG) and set a ≥ 60 percent HHV efficiency requirement for CHP. Assembly Bill 2778 (AB 2778) (Lieber, Chapter 617, Statutes of 2006) limited the SGIP to fuel cells and wind from 1/1/2008 to 1/1/2012 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 its 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."

AB 1613 clearly includes electricity and thermal energy as output energy forms. The Committee Proposed 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 also 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 industry, 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 definition and determination of "useful" is one of the more important aspects of developing the Proposed Committee Guidelines.

Title 18 of the Code of Federal Regulations, Section 292.202 (g) 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 pursuant to section 1253 of the Energy Policy Act of 2005 (EPAct 2005) and section 210 of the Public Utility Regulatory Policies Act of 1978 (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 industry, commercial residential or institutional purposes; and (3) there is continuing progress in the development of efficient electric generating technology.

Section 292.205 (d) (1) 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 productive and beneficial. FERC declined "to institute a bright line or specific standards concerning what constitutes acceptable thermal output." Instead FERC "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 Committee Proposed Guidelines require that the applicant show that the thermal output is useful 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 and (2) under "average annual hourly operating conditions," a concept contained in FERC regulations, 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 Committee Proposed Guidelines diverge from FERC on the continued satisfaction of the "productive and beneficial" requirement. For the purposes of AB 1613, 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.

Setting the Minimum Efficiency Level

As noted above: (1) a 60 percent minimum efficiency level has been set for participation in the SGIP and (2) AB 1613 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 standard should apply at other than full load (that is, over some operational range) and whether additional efficiency measures should be proposed for adoption.

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:

$$\text{Fuel Savings} = 1 - \{Fave / [Pave/Eff_P + Mave/Eff_M + Qave/Eff_Q]\}$$

- 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.

Note that the energy values must be in the same unit.

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. One disadvantage of the Fuel Savings metric is that it requires the specification of the efficiency of the displaced grid electricity system. A second disadvantage is that the displaced grid electricity system and the displaced boiler must be characterized as they would have actually operated. The Committee Proposed Guidelines require the CHP system owner/operator to report operating data on an annual basis. Hypothetical "what if" operation of a non-existent displaced power plant or power plant mix is a questionable basis for comparison. 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).

Energy Commission staff has begun an investigation to determine if one methodology can be used to specify the displaced central power plant for multiple purposes, and especially the GHG emission reductions from energy efficiency, renewable energy, and CHP applications. Initial results will be available in early 2010, at which time consideration of adding a Fuel Saving Standard to amended Guidelines will be considered.

Ray Williams of PG&E, in testimony presented before the October 12, 2009 Electricity and Natural Gas 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, such as that 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 Committee Proposed Guidelines, as adopted, should ensure that every CHP system that obtains an AB 1613 contract reduces GHG emissions.

Keith Davidson of DE Solutions, Inc. presented a methodology at the October 26, 2009, workshop on AB 1613 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 80–85 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.

PG&E's graphical presentation shows that the Guidelines can be simplified by adopting only an efficiency level. The fuel savings standard replaces the efficiency standard only at extremes of low power-to-heat ratios (when P/H is less than 0.5 and the 80 percent boiler efficiency becomes effective) and high power-to-heat ratio (when P/H is greater than 3.0 and the 15 percent minimum thermal requirement becomes effective). CHP systems with P/H ratios below 0.5 will probably have little electricity export after satisfying on-site electrical needs. PG&E notes that high P/H ratios "are not contemplated by AB 1613."

The above considerations suggest that only one efficiency metric, the Energy Conversion Efficiency, is needed for the Committee Proposed Guidelines in the near term.

Don Schoenbeck, representing the Energy Producers and Users Coalition and the Cogeneration Association of California, compared efficiencies of CHP systems on the Southern California Edison (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 CHP market assessment study described in the 2009 IEPR proceeding and in a draft report can guide the selection of this efficiency value. Table 43 of the ICF International Report *Combined Heat and Power Market Assessment*, PIER Project Draft Report CEC-500-2009-094-D provides "effective CHP efficiencies" for those CHP systems that are forecast to be installed under five different 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. In order 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 AB 1613, the effective CHP efficiencies for the mix of technologies that are forecast to enter the market are between 62.3 and 62.8 percent.

AB 1613 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 useful energy output value depends significantly on the thermal energy utilization efficiency. At 100 percent thermal utilization, the ICF International prototype CHP systems have efficiencies between 59 percent and 79 percent. At 80 percent thermal energy utilization, the prototype CHP systems have useful energy output efficiencies between 58 percent and 74 percent. Acrosss all candidate new CHP applications, an 80 percent thermal utilization assumption is more realistic than a 100 percent thermal utilization assumption.

PURPA discounts 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. This arbitrariness would be eliminated in a double benchmarking approach, if convergence on the value of the double benchmarks could be achieved.

The Committee Proposed Guidelines recommend 62 percent as a technologically achievable and economically feasible minimum efficiency level for Topping Cycle CHP Systems. This is above the AB 1613 minimum efficiency requirement and above the median efficiency of CHP systems connected to the SCE system.

ICF International did not do a market penetration forecast for Bottoming Cycle CHP systems. In the absence of an economic assessment for Bottoming Cycle CHP systems and in the absence of disaggregated empirical data for Bottoming Cycle CHP systems, the Committee Proposed Guidelines recommend the minimum efficiency level of 60 percent in AB 1613 for Bottoming Cycle CHP systems with supplemental firing. For a Bottoming Cycle CHP system without supplementary firing, the fuel chargeable to power is zero and the net fuel heat rate is zero. This implies infinite electrical generation efficiency. In recognition of this situation, both FERC and the Committee Proposed Guidelines exempt Bottoming Cycle CHP systems without supplementary firing from an energy output efficiency standard.

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.

Environmentally Beneficial, Especially with Respect to Greenhouse Gas Emissions

Recommended Requirement

The Committee Proposed Guidelines capture the GHG emission requirement by requiring an efficiency of 62 percent, which corresponds to 650 lbs CO_2/MWh, well below the 1,100 lb/MWh AB 1613 requirement. 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 Order Instituting Rulemaking 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 Committee Proposed 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 (SB 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 (EPS) and "significant reductions" in greenhouse gas emissions.

Under Section 2845, the ARB is responsible for reporting GHG emissions reductions associated with the installation of CHP systems qualifying for the AB 1613 tariff. 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.

The Act requires the ARB to report to the Governor and the Legislature by December 31, 2011, on GHG emission reductions resulting from CHP system installations and to recommend policies that further the goals of AB 1613. The Committee recommends that the ARB recommendations include suggested changes to the adopted AB 1613 Guidelines to achieve the objectives of AB 1613.

Rationale

Most CHP systems are fueled by natural gas, and the most important greenhouse gases are carbon dioxide and methane, with methane being a more potent GHG. CHP system efficiency and carbon dioxide emissions are directly linked. Reductions in CO_2 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.[4] Hourly CO_2 emission factors were based on a methodology initially developed by Energy and Environmental Economics (E3) 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

[4] Seventh Year Impact Evaluation Report, Section 5 and Appendix B

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 Proposed Committee Guidelines require that 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.

A fourth consideration is the size of the displaced central station resource. The CPUC Proposed Decision Adopting Policies and Procedures for Purchase of Excess Electricity under Assembly Bill 1613 in Rulemaking 08-06-024, filed on October 30, 2009, sets an interim cap of 500 MW on the amount of power purchased under AB 1613 as being helpful for planning purposes. In applying the cap, the decision refers to the 500 MW being "based on the export capacity of participating CHP…." and "based on the maximum size of eligible CHP…." The Proposed Decision also allocates the cap among utilities, with allocations ranging between 0.005 MW and 247.7 MW. A 0.005 MW power plant will not be a combined-cycle. Utility comments on the two Pricing Options proposed by the Energy Division staff claim that CHP does not provide the same value as an NGCC, in that a NGCC can provide firm power and ancillary services, and thus CHP should not be paid as though they are a NGCC. In contrast, at the Energy Commission proceeding, utilities argued that CHP should perform as well as an NGCC in establishing a double benchmark. Investor owned utility positions don't seem to be consistent between the two proceedings. A CHP system that is not paid as though it were a NGCC should not be required to perform as though it were a NGCC. The proposed CPUC decision accepts the utility argument expressed as an Order that "Energy Division staff's recommendation to base pricing on the costs of a combined cycle gas turbine is adopted, but a derating factor of 40% shall be applied to the fixed component of the price to reflect the lower value of as available power."

The previous considerations provide further rationales for not adopting a fuel savings standard based on double benchmarks and argue for a systematic investigation of appropriate benchmarks and the modes of operation

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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 Guidelines adopt the legislative requirement without change. The NO_x emission limits are as strict as any of those adopted in California.

Other than GHGs (including N_2O), no other pollutant species are mentioned in the Act. Other criteria pollutant emission requirements are under the jurisdiction of the U.S. EPA, the ARB, and local air quality management districts.

Chapter 5: Application Process

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 Form CEC-2843 and demonstrated compliance with the Guidelines.

Legislative Requirement Satisfied

Sections 2841, 2842.2, 2843, 2845

Rationale:

AB 1613 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 CPUC will include the Guidelines into a contract for the sale of electricity to an electrical corporation. Evidence that a qualifying CHP system will meet the performance requirements in the Committee Proposed Guidelines is accomplished via the submittal of Application Forms, the review of those forms by the Executive Director, and the certification of a qualifying CHP system. The parties to the tariff or contract can appeal the Executive Director's decision. The Applicant must declare that the information provided in the Form is accurate and in compliance with the Committee Proposed Guidelines.

The information requirements are similar to those in the SGIP which was limited to smaller DG and CHP systems.

Other alternatives for showing compliance with the Guidelines were considered, both in terms of the scope and detail of the information submitted, the demonstration of accuracy of the information, and the reviewing entity and review processes. The scope and detail of the information requested is necessary to perform the calculations confirming that the performances standards will be met. The fuel input and electricity output is relatively easy to measure and report. The thermal energy production and usage is more difficult to predict and to measure. However, on an energy output basis, the useful thermal energy is as valuable an energy output as the electricity. The essence of AB 1613, that waste heat be utilized, requires that credit be given for only the recovered thermal energy and that thermal energy discharged to the environment be denied credit. Some stakeholders have argued that the Application Form be signed by a Professional Engineer. The intricacies of quantifying the thermal energy flows could be an argument for such a requirement.

However, such a requirement could be burdensome for small CHP systems, especially those with minimal export and hence sales revenue.

Chapter 6: Annual Reporting and Verification

Recommended Requirement

Every calendar year each qualified CHP system Owner/Operator 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)

AB 1613 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 Committee Proposed Guidelines go beyond the requirements in AB 1613 by requiring the annual reporting of CHP system performance as relevant to comply with the Guidelines, if adopted, during each year of operation and electricity export. The annual reporting requirement is imposed based 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 a 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 AB 1613 efficiency and emission reduction goals are achieved over the life of the CHP systems.

The Committee Proposed Guidelines require that the Owner/Operator monitor and report on CHP system performance. Some of the monitoring and reporting may be required by the ARB in its implementation of AB 32, and as such the Committee Proposed Guidelines do not impose an additional monitoring or data collection burden.

The Committee Proposed 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.

Chapter 7: Issues Associated With the Application of And Satisfaction of the Guidelines

Tiering of Performance Standards and/or Reporting Requirements

The Proposed Committee Guidelines do not make any distinction as a function of CHP system size or amount of electricity generation per year. As with the double benchmark and fuel saving methodologies, the introduction of numerical limits or thresholds where different performance requirements apply creates disagreement among stakeholders.

The Proposed Committee Guidelines are simpler to apply and to comply with than staff versions of the draft Guidelines.