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Exhibit # : Alliance 5 (Late-filed)

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RE: APS / Re Four Corners
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Please place the following **LATE-FILED** Exhibit Alliance-5 in the Docket file.

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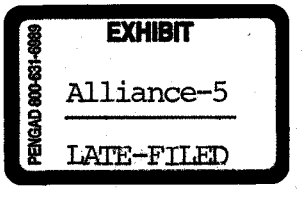
Exhibit Alliance-5 (Late-Filed)

Docket No. E-01345A-10-0474
Arizona Public Service Company



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Decision 07-01-039 January 25, 2007

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Implement the Commission's Procurement Incentive Framework and to Examine the Integration of Greenhouse Gas Emissions Standards into Procurement Policies.	Rulemaking 06-04-009 (Filed April 13, 2006)

INTERIM OPINION ON PHASE 1 ISSUES: GREENHOUSE GAS EMISSIONS PERFORMANCE STANDARD

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INTERIM OPINION ON PHASE 1 ISSUES: GREENHOUSE GAS EMISSIONS PERFORMANCE STANDARD

1. Introduction and Summary[1]

Today, we adopt an interim greenhouse gas (GHG) emissions performance standard for new long-term financial commitments to baseload generation undertaken by all load-serving entities (LSEs), consistent with the requirements and definitions of Senate Bill (SB) 1368 (Stats. 2006, ch. 598).[2] Our adopted emissions performance standard or "EPS" is intended to serve as a near-term bridge until an enforceable GHG emissions limit applicable to LSEs is established and in operation.[3] At that time, as directed by SB 1368, we will reevaluate and continue, modify or replace this standard through a rulemaking proceeding, and in consultation with the California Energy Commission (CEC) and the California Air Resources Board (CARB).

As discussed in this decision, an EPS is similar to an energy efficiency appliance standard. If a consumer wants to purchase a new refrigerator in California, for example, he or she has a variety of models to choose from--each with a different upfront purchase price, operating cost and other design attributes. However, at a minimum, each refrigerator must meet the threshold for appliance efficiency established by the standard. Similarly, SB 1368

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[1] Attachment 1 describes the abbreviations and acronyms used in this decision.

[2] Attachment 3 presents the full text of SB 1368. The statute defines LSEs as "every electrical corporation, electric service provider, or community choice aggregator serving end-use customers in the state." (Public Utilities Code § 8340(h), added by SB 1368.) All subsequent references to sections refer to the Public Utilities Code, unless otherwise specified.

establishes a minimum performance requirement for any long-term financial commitment for baseload generation that will be supplying power to California ratepayers.[4] The new law establishes that the GHG emissions rates for these facilities must be no higher than the GHG emissions rate of a combined-cycle gas turbine (CCGT) powerplant.[5]

An EPS is needed to reduce California's financial risk exposure to the compliance costs associated with future GHG emissions (state and federal) and associated future reliability problems in electricity supplies. Put another way, it is needed to ensure that there is no "backsliding" as California transitions to a statewide GHG emissions cap: If LSEs enter into long-term commitments with high-GHG emitting baseload plants during this transition, California ratepayers will be exposed to the high cost of retrofits (or potentially the need to purchase expensive offsets) under future emission control regulations. They will also be exposed to potential supply disruptions when these high-emitting facilities are taken off line for retrofits, or retired early, in order to comply with future regulations. A facility-based GHG emissions performance standard protects California ratepayers from these backsliding risks and costs during the transition

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[3] We use the terms "GHG emissions performance standard," "standard," and "emissions performance standard" (or "EPS") interchangeable throughout this decision.

[4] SB 1368 directs this Commission to adopt an EPS for all LSEs, as that term is defined above, and directs the CEC to implement an EPS for all of the local publicly owned electric utilities (by June 30, 2007) consistent with the standard we adopt herein. (§ 8341(e)).

[5] Throughout this decision, we use the term CCGT powerplant to refer to a "combined cycle natural gas plant" as defined in SB 1368. More specifically, CCGT powerplant refers to a powerplant that "employs a combination of one or more gas turbines and steam turbines in which electricity is produced in the steam turbine from otherwise lost waste heat exiting from one or more of the gas turbines." (§ 8340(b).)

to a load-based GHG emissions cap. As directed by SB 1368, we have considered the effects on system reliability and overall costs to electricity customers in developing an EPS that will achieve these objectives.[6]

SB 1368 provides specific direction on many design and implementation aspects of the EPS. We briefly describe that direction in the following summary of today's adopted standard.

1.1. Covered Procurements

SB 1368 describes what types of generation and financial commitments will be subject to the EPS ("covered procurements"). Under SB 1368, the EPS applies to "baseload generation," but the requirement to comply with it is triggered only if there is a "long-term financial commitment" by an LSE. The statute defines baseload generation as "electricity generation from a powerplant that is designed and intended to provide electricity at an annualized plant capacity factor of at least 60%."[7] For LSE-owned baseload generation, a long-term financial commitment occurs when there is a "new ownership investment." For baseload generation procured under contract, there is a long-term commitment when the LSE enters into "a new or renewed contract with a term of five or more years."[8]

SB 1368 provides that CCGT baseload powerplants currently in operation, or that have a CEC final permit decision to operate as of June 30, 2007, shall be

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[6] § 8341 (d)(6).

[7] § 8340 (a).

[8] § 8340 (j).

"deemed to be in compliance" with the EPS. We refer to these § 8341(d)(1) grandfathered powerplants as "deemed-compliant" CCGT powerplants.

During the workshop process and in their comments, parties debated the issue of how the EPS should apply to existing facilities owned by the LSE and used to serve its load (referred to as "retained generation"). Based on our reading of SB 1368, we find that the "new ownership investment" trigger for EPS compliance includes LSE investments in retained generation. Except for deemed-compliant CCGTs, we define that trigger as any LSE investment that is intended to extend the life of one or more units of an existing baseload powerplant for five years or more, or results in a net increase in the existing rated capacity of the powerplant.[9] Only those units in a multi-unit generating facility that are being added, replaced or altered must comply with the EPS. A new ownership investment is also triggered if the investment is intended to convert an existing non-baseload powerplant to a baseload powerplant.

However, for deemed-compliant CCGT baseload powerplants, we conclude that the type of investment described above does not necessarily trigger a requirement to comply with the EPS—for either LSE-owned CCGT powerplants (under the "new ownership investment" trigger) or for non-LSE owned powerplants (under the "new or renewal contract" trigger). As discussed in this decision, to construe SB 1368 otherwise would violate fundamental rules of statutory construction by rendering certain sections meaningless or redundant. At the same time, we find that SB 1368 cannot be construed to mean

[9] "Rated capacity" refers to the plant's maximum rated output under specific conditions designated by the manufacturer and usually indicated on the nameplate physically attached to the generator.

that all new capacity added to a deemed-compliant CCGT powerplant should also be excused from demonstrating actual compliance with the EPS. This would achieve an absurd result by allowing an owner of a deemed-compliant CCGT powerplant to circumvent the EPS by simply co-locating additional units and capacity with existing units at a previously deemed-compliant powerplant.

To avoid this absurd result and give meaning to each section of the statute, we require that units added to a deemed-compliant CCGT powerplant that result in an increase of 50 megawatts (MW) or more to the powerplant's rated capacity must meet the EPS. We select a 50 MW threshold because it demarcates the boundary between significant and minor changes in generating capacity for the purpose of triggering CEC powerplant permitting requirements under Public Resources Code § 25123. This means that an LSE must demonstrate compliance with the EPS whenever the LSE adds units to one of its own deemed-compliant CCGT powerplants if those additions result in an increase of 50 MW or greater to the powerplant's rated capacity. In addition, the LSE must demonstrate compliance with the EPS whenever it enters into new or renewal contract with a deemed-compliant CCGT powerplant to which units have been added that result in an increase of 50 MW or greater to the powerplant's rated capacity.[10] In both cases, however, only the added units must meet the EPS.

Some parties urge us to also require that investor-owned utilities demonstrate compliance with the EPS any time the utility seeks rate

[10] For the purpose of establishing when there has been a 50 MW addition, the existing rated capacity will be determined as follows: 1) for all CCGT plants that are in operation on the effective date of this decision – the rated capacity of the plant that is operating, or 2) for all other plants (or additions to plants) that obtain a CEC final permit to operate by June 30, 2007 – the rated capacity authorized by the permit.

modifications or submits procurement plans supporting retained baseload generation, irrespective of whether new investments are made to those facilities. This position is inconsistent with the plain language of SB 1368, which provides clear direction as to what triggers the requirement to apply the EPS. Therefore, we only require a demonstration of EPS compliance for retained baseload generation when the LSE makes a new investment in those facilities, as discussed above.

In sum, the interim EPS will apply to the following long-term financial commitments made by an LSE to baseload generation ("covered procurements"):

(1) New ownership investments in baseload generation made by an LSE, defined as:
   (a) Investments in new baseload powerplant (new construction).
   (b) Acquisition of new or additional ownership interest in existing baseload powerplant previously owned by others.
   (c) New investments in the LSE's own existing, non-CCGT baseload powerplants that: 1) are designed and intended to extend the life of one or more units by five years or more, 2) result in a net increase in the rated capacity of the powerplant, or 3) are designed and intended to convert a non-baseload plant to a baseload plant, or
   (d) Units added to a deemed-compliant CCGT plant that result in an increase of 50 MW or more to the powerplant's rated capacity, or

(2) New contract commitments (including renewal contracts) of five years or greater by an LSE with:
   (a) baseload generation facilities, unless those facilities represent deemed-compliant CCGT powerplants, or
   (b) any deemed-compliant CCGT powerplant that added units resulting in an increase of 50 MW or more to the powerplant's rated capacity. (The contracting LSE need only show that the added units meet the EPS.)

Based on the definition of "powerplant" adopted in this decision, the EPS will generally be applied to each individual generating unit supplying power under the covered procurements listed above. (See Section 4.2.4.)

1.2. EPS Performance Level (Emissions Rate)

Pursuant to SB 1368, the performance level of the EPS must be "no higher" than the emissions rate of a CCGT powerplant.[11] However, the statute does not specify the emissions rate for a CCGT powerplant. Based on our review of emissions rates associated with a broad range of CCGT powerplants of varying vintages, we adopt an EPS emissions rate of 1,100 pounds of carbon dioxide (CO_2) per megawatt-hour (MWh).[12] Based on the record in this proceeding, we find that this level reflects the intent of the Legislature to base the EPS on representative CCGT emissions rates. As discussed in this decision, a 1,100 lbs/MWh standard reasonably accounts for potential CCGT plant "outliers" from the average data on CCGT emissions rates to accommodate those units that utilize dry cooling technologies, are smaller-sized facilities or are located in the desert or at high altitudes. At the same time, our adopted level avoids establishing a performance standard that is representative of the most inefficient, older CCGT powerplants currently in operation. We believe that this is appropriate in light of the statute's grandfathering provisions, which reflect the Legislature's concern that some of the older, less efficient CCGT powerplants in operation may not be able to meet the standard.

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[11] § 8341(d).

[12] We discuss in Section 4 below why today's adopted standard focuses on CO_2 emissions.

1.3. Application of EPS to Contracts

The threshold design issue debated in this proceeding was the application of the interim EPS to contracts. All parties agree that the characteristics of the facility supplying the energy should be considered when applying the adopted standard to new ownership investments. However, there was considerable disagreement over whether the same should apply when considering contract commitments. The issue came down to whether we should apply the performance standard to the underlying facility or to the contracted-for deliveries.

In particular, when a summer product delivered under a new or renewal contract (with a term of five years or greater) from a baseload facility represents less than 60% of that facility's annual average output, some parties recommend that the contract be considered "non-baseload" and therefore exempt from the standard. Similarly, some parties recommend that only the amount of contracted-for deliveries from customer generators to the LSE should determine whether or not the standard applies to the contract.

Several parties also recommend that the capacity factors and emissions rates of multiple powerplants be "blended" when two or more deliver power under a single contract. Under our refrigerator analogy, this approach would permit a customer to purchase two different refrigerator models, one that does not meet the minimum level of efficiency under the appliance standard and one that is more efficient than the standard, such that the average efficiencies of the two meet the required efficiency performance level. The blending approach suggested by parties in the context of the EPS would also permit the averaging of plant capacity factors to determine whether or not the standard applies. In practice, this means that a powerplant generating electricity at a 60% or greater

annualized capacity factor (baseload generation) might not be subject to the EPS if the contract also includes deliveries from a powerplant generating electricity at a capacity factor below 60%, depending upon the relative amount of power to be delivered by each facility.

We find that the goals of SB 1368 and this Commission's GHG reduction policies require us to look at the characteristics and emissions of each individual powerplant being contracted for, *not* just the characteristics of the contracted-for-deliveries or the blended combination of multiple facilities or resources. Indeed, as discussed throughout this decision, it is the very characteristics of the powerplants underlying long-term financial commitments that create the potential financial and reliability risks to California consumers that this Commission and the Legislature seek to reduce through the EPS. Moreover, the language of the statute itself supports a facility-based application of the standard. In particular, SB 1368 directs:

> "In determining whether a long-term financial commitment is for baseload generation, the commission ***shall consider the design of the powerplant and the intended use of the powerplant...*** " [13]

Accordingly, the rules we adopt today require a facility-based application of the EPS. For contracts with multiple generating sources, each specified powerplant must be treated individually for the purpose of determining both the annualized capacity factor and net emissions.

At the same time, we recognize the importance of renewable resources for the achievement of the state's energy policies, as does SB 1368. [14] In the process

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[13] § 8341 (b)(4), emphasis added.

[14] See SB 1368, Section 1 (c) and (d).

of meeting the requirements and goals of the statute, we therefore strive to avoid creating impediments to long-term contracting with these resources. As discussed in the following section, we adopt rules for the use of substitute system energy purchases in long-term contracts that provide a reasonable level of contracting flexibility for firming deliveries with renewables without undermining the objectives of SB 1368.

1.4. Unspecified Contracts

SB 1368 also directs us to address long-term purchases of electricity from unspecified sources in a manner consistent with the statute.[15] We considered in this proceeding whether it would be consistent with the statute to impute a specific emissions rate to unspecified contracts and, if so, what proxy rate to utilize for this purpose. We use the term "unspecified contracts" to refer to contracts (power purchase agreements) that are not linked to any particular generating source. We also refer to these types of contracts as "system energy" contracts or purchase agreements, and we use these terms interchangeably in this decision.

In order to comply with SB 1368's mandate that we address unspecified sources in a manner consistent with the rest of the statute we must ensure that:

(1) LSEs only enter into long-term financial commitments with baseload generation that comply with the EPS, and

(2) EPS compliance cannot be achieved in a manner that would yield a contrary result, i.e., that results in an increase in long-term commitments with high-emitting sources.

In considering how best to achieve these objectives, we examined various approaches presented during the workshop process and in written comments for

imputing an emissions value to unspecified contracts. These include approaches that use 1) Western Energy Coordinating Council (WECC) calculations of average emissions rates for generation activities throughout the western states or by specific geographic region, and 2) the California Net Power Mix information produced by the CEC for power content labeling. Based on the record in this proceeding, we conclude that imputing emissions rates to unspecified contracts would not be consistent with the requirements of SB 1368 for the following reasons.

First, we have difficulty reconciling the concept of imputed emissions rates with the requirements of SB 1368 since, by definition, such proxies do not reflect the actual emissions from the underlying resources. As a result, using imputed emissions rates does not permit us to determine whether a commitment with an unspecified resource is consistent with SB 1368 or simply exacerbates the problems this Commission and the Legislature are trying to address.

Moreover, any method to impute a GHG emissions rate to unspecified resources results in a binary outcome in the context of an EPS – that is, all financial commitments with unspecified resources will either "pass" or "fail" based on the selected level of imputed emissions. As a result, there is enormous pressure to game the methodology and input assumptions used for this purpose, thereby making it very difficult and contentious to implement this particular approach to addressing unspecified contracts. Finally, as discussed in Section 4.12, none of the specific proxy approaches recommended by Commission staff or in parties' comments are reasonable or workable for our purposes, at least not at this time.

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[15] § 8341(d)(7).

Therefore, instead of imputing an emissions rate to unspecified contracts, we require in today's decision that all covered procurements be with specified resources that can demonstrate compliance with the interim EPS, except when substitute system energy is purchased to firm deliveries from specified powerplants under the limited conditions we describe below. For the reasons discussed in this decision, we conclude that addressing unspecified contracts in this manner is consistent with the rest of the statute, as SB 1368 requires.[16] Moreover, this treatment of unspecified contracts does not permit gaming that could result in the opposite outcome than the statute intended, i.e., an *increasing* number of long-term commitments to high GHG-emitting resources.

Based on the record in this proceeding, we also conclude that it is highly unlikely that LSEs will need to enter into any new or renewal power purchase contracts of five years or greater that are unspecified during the transition to a statewide GHG emissions limit. As discussed in this decision, in the event that an LSE must enter into a long-term unspecified contract to address system reliability concerns, it may request Commission consideration of a reliability exemption from this requirement, on a case-by-case basis. Further, today's decision allows for the purchase of substitute system energy to firm deliveries from EPS-compliant, specified powerplants, within certain boundaries, in order to address the need expressed by LSEs and other parties for this type of contracting flexibility.

In view of the above, a requirement that all long-term contracts with baseload generation be with "specified" resources that can demonstrate EPS compliance should not have a significant, if any, impact on an LSE's resource

[16] § 8341 (a), (b)(1), (b)(3) and (d)(1).

procurement flexibility. By "specified" we mean that the contract identifies the powerplant(s) that will be delivering power under the contract. However, the following circumstances would also comply with our EPS rules: First, if the long-term contract specifies that power will be delivered exclusively from pre-approved renewable technologies or resources (see Section 1.6 below) and there are assurances in the contract to that effect, then the contract would comply with the EPS even if none of the generating sources are specified. Second, if a group of powerplants from which power will be delivered under a contract is specified, and there are assurances in the contract that deliveries will only be from one or more of the powerplants in that group *and* each of those that are baseload powerplants would individually pass the EPS, then the contract would comply with the EPS. The burden is on the LSE to provide sufficient documentation to demonstrate compliance with the EPS under these circumstances.

As discussed in this decision, today's adopted EPS rules with respect to unspecified contracts are also consistent with our discussion of emissions registration in Decision (D.) 06-02-032 and a logical interim step towards the implementation of Assembly Bill (AB) 32 (Stats. 2006, ch. 488).[17] As we note in today's decision, other jurisdictions have developed specific resource tagging mechanisms to track generation attributes, including GHG emissions, of resources within their control areas. In our view, it is entirely feasible to implement a program that tracks the GHG emissions of all generating units, and that would enable marketers and other sellers of unspecified resource contracts

[17] See D.06-02-032, p. 38. Among other things, AB 32 requires CARB to adopt a statewide GHG emissions limit equivalent to the statewide GHG emissions levels in 1990, to be achieved by 2020, in consultation with this Commission.

to assign a reasonable and accurate GHG emissions profile to their contracts. This should be the strategy pursued by California to deal with emissions from any unspecified resource contracts that LSEs may wish to pursue; however, as the record shows, this is not a likely pursuit for the types of LSE long-term procurements subject to the interim EPS.

While LSEs have stated that they are not likely to pursue long-term unspecified contracts as a general rule, they do intend to continue to negotiate long-term contracts with specified powerplants that contain "substitute energy provisions," i.e., provisions that permit the seller to substitute system energy on a short-term basis as needed for operational or efficiency reasons. We are persuaded from the comments in this phase of the proceeding that these types of provisions can provide greater performance assurance at more moderate price to ratepayers, and that appropriate restrictions to their usage can be put in place to guard against the intentional sourcing of energy from high carbon intensive baseload resources. Accordingly, based on proposals submitted by Pacific Gas and Electric Company (PG&E) and the Sacramento Municipal Utilities District (SMUD) in this proceeding, we permit LSEs to enter into contracts with a term of five years or longer that include provisions for substitute system energy purchases under the following circumstances:

1. The contract is with one or more specified powerplants, each of which is EPS-compliant under our adopted rules.
2. For specified contracts with non-renewable resources or dispatchable renewable resources (or a combination of each), substitute energy purchases for each specified powerplant are permitted up to 15% of forecast energy production of the specified powerplant over the term of the contract, provided that the contract only permits the seller to purchase system energy under either of the following conditions:

a) The contract permits the seller to provide system energy when the powerplant is unavailable due to a forced outage, scheduled maintenance or other temporary unavailability for operational or efficiency reasons; or

b) The contract permits the seller to provide system energy to meet operating conditions required under the contract, such as provisions for number of start-ups, ramp rates, minimum number of operating hours, etc.

A "dispatchable" renewable resource for the purpose of this rule is one that is not defined as "intermittent" under section 3 below.

3. For specified contracts with intermittent renewable resources (defined as solar, wind and run-of-river hydroelectricity), the amount of substitute energy purchases from unspecified resources is limited such that total purchases under the contract (whether from the intermittent renewable resource or from substitute unspecified sources) do not exceed the total expected output of the specified renewable powerplant over the term of the contract.

1.5. Calculation of Emissions Associated with Cogeneration

SB 1368 requires us to adopt a methodology for calculating the emissions rate associated with cogeneration facilities that recognizes both the thermal output (heat or steam) and electrical output associated with cogeneration.[18] In today's decision, we consider several approaches to this requirement and adopt the "conversion method." Under this method, the emissions rate is calculated by dividing the total GHG emissions from a cogeneration facility by the sum of its kilowatt-hour (kWh) output plus the usable thermal energy output (expressed in kWh) produced by the facility. For this calculation, the thermal energy output is

[18] § 8341(d)(3).

converted from British thermal unit (Btu) into a kWh equivalent using the standard engineering conversion factor of 3413 Btu per kWh.

There was some debate in this proceeding over how to define "useful thermal energy" for this calculation. We adopt the definition used by the Federal Energy Regulatory Commission (FERC) in its regulations mandating the minimum efficiencies of a cogeneration qualifying facility (QF).[19] Based on this definition, the calculation of emissions rates for cogeneration facilities should include the thermal energy that is actually intended to be delivered to the thermal host, and not include remaining thermal energy intended to be exhausted as waste heat.

As discussed in this decision, all existing cogeneration facilities complete an annual questionnaire submitted to the interconnecting utility to demonstrate compliance with FERC efficiency requirements. On this form, the cogenerator presents monthly and annual values for energy input, useful power output and useful thermal output. For the purpose of the interim EPS, we will base a cogenerator's emissions rates on the values presented in these questionnaires, which are readily available from the interconnected utility. For new cogeneration facilities, when this questionnaire has not been submitted to the utility, the EPS will be determined based on reasonably projected emissions of the facility, which can be based on readily available information in FERC Form 556, required for QF certification.

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[19] A QF is a generating facility that meets the requirement for QF status under federal law and FERC regulations governing such facilities. QFs can be cogeneration facilities of any size or small power production facilities (up to 80 MW) where the primary energy source is renewable.

We emphasize, however, that we adopt the above approach for calculating and documenting cogeneration emissions rates for the limited purpose of demonstrating compliance with the interim EPS. Our determinations today are in no way intended to prejudge or predetermine what approach may be established in the context of our Procurement Incentive Framework or under the statewide GHG emissions limit envisioned under AB 32.

1.6. Emissions Rates of Renewables and "Null" Renewable Power

As summarized in Figure 1, the record in this proceeding supports an upfront determination that the following renewable resources and technologies are EPS-compliant:

- Solar Thermal Electric (with up to 25% percent gas heat input)
- Wind
- Geothermal, with or without reinjection
- Generating facilities (e.g., agricultural and wood waste, landfill gas) using biomass that would otherwise be disposed of utilizing open burning, forest accumulation, landfill (uncontrolled, gas collection with flare, gas collection with engine), spreading or composting.

In particular, the record shows that electric generation using biomass (e.g., agricultural and wood waste, landfill gas) that would otherwise be disposed of under a variety of conventional methods (such as open burning, forest accumulation, landfills, composting) results in a substantial *net reduction* in GHG emissions. This is because the usual disposal options for biomass wastes emit large quantities of methane gas, whereas the energy alternatives either burn the wastes that would become methane or burn the methane itself, generating CO_2. Since methane gas is on the order of twenty to twenty-five times more potent as a GHG than CO_2, and since methane has an atmospheric residence time of twelve

years, after which it is converted to atmospheric CO_2, trading off methane for CO_2 emissions from energy recovery operations leads to a net reduction of the greenhouse effect.[20]

In practice, this means that an LSE does not have to demonstrate compliance with the EPS for long-term financial commitments with baseload generation utilizing any of the renewable resources and technologies listed above. Such commitments get an automatic "pass" through the gateway screen described below. If and when there is sufficient data so that parties believe that the Commission could make determinations to pre-approve additional renewable resources and technologies, parties may file a Petition for Modification of this decision to augment the above list. There was considerable debate over how to attribute emissions factors to renewable resources that have sold off their renewable energy credits or "RECs." The term "null renewable power" refers to those renewable resources that have transferred their renewable attributes through the sale of RECs. In the context of making the EPS "go, no-go" commitment decision, parties raised the issue of whether renewable resources should be "stripped" of their GHG emissions attributes if they have sold RECs and if so, what emissions rate should be assigned to that null renewable power for the purpose of evaluating EPS compliance.

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[20] For the biomass technologies identified above, which utilize landfill gas, agricultural and wood waste as the biomass fuel source, by definition there are no emissions associated with growing the fuel. As discussed in this decision, an LSE entering into a long-term financial commitment with a biomass generating project where growing the fuel is required will need to calculate net emissions taking into account the emissions associated with "growing," as well as "processing and generating" the electricity from the fuel source pursuant to § 8341(d)(4).

As discussed in this decision, among other potential purposes, the trading of RECs would provide a flexible compliance option to LSEs for meeting their Renewable Portfolio Standard (RPS) obligations.[21] We have identified the investigation of a tradable REC system as one of the tasks for Rulemaking (R.) 06-02-012 and plan to initiate this investigation during 2007. We therefore cannot predict at this time whether, how or when a regulatory REC market will develop in California. Some parties propose that we defer the issue of how to treat null renewable power for the purpose of EPS compliance until we complete our investigation of a tradable REC system. However, we reject this approach because of the potentially dampening effect that this uncertainty could have on the development of renewable resources.

For the purposes of demonstrating compliance with the interim EPS, we determine that the emissions rate for renewables should be calculated based on the operations and emissions profile of the renewable resource, irrespective of whether RECs associated with that facility are sold. We reach this determination for several reasons. In particular, we conclude that stripping renewables of their emissions profile if RECs are sold could easily create a "perverse" result; namely, to discourage long-term commitments with renewable generators that have zero, low or even negative net GHG emission profiles, in favor of higher emitting facilities.

Moreover, in the context of EPS compliance, we find that retaining the emissions attributes of the renewable facility when RECs are sold does not create

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[21] By law, electricity generated from eligible renewable energy resources must equal at least 20% of the total electricity sold to retail customers in California per year by December 31, 2010. (SB 107, Stats. 2006, ch. 464.)

a double counting problem, as some suggest in this proceeding. This is because the EPS is a "go-no go" investment standard separate from RPS compliance, and as discussed above, each facility has to pass the EPS on its own emissions-generating merits. In other words, a high-emitting facility would not be able to use a purchased REC for the purpose of reducing (or blending) its emissions to demonstrate compliance with the EPS. Therefore, there is nothing to double count here, since RECs would not have any value for EPS compliance. Moreover, our treatment of RECs in the context of the EPS is not inconsistent with § 399.12, as amended by SB 107, which provides that a REC "includes all renewable and environmental attributes associated with the *production* of electricity" (emphasis added), not discrete investment decisions.

For these and other reasons, we determine that the emissions profile of a renewable resource will not change for the purpose of demonstrating EPS compliance if or when the owner sells the RECs associated with that baseload facility. This also means that purchased RECs cannot be used by an LSE to lower the emissions of a baseload facility for the purpose of demonstrating EPS compliance. However, we emphasize that today's determination on how to treat null renewable power and associated RECs is specific to the application of the interim EPS. This determination in no way guarantees that null renewable power will be assigned a zero or low GHG emissions value in the context of either the Procurement Incentive Framework we are implementing in Phase 2 of this proceeding, or the statewide GHG emissions limits adopted by the Legislature in AB 32.

1.7. Exemptions from the Interim EPS

As discussed above, SB 1368 exempts from the EPS any CCGT baseload powerplant that is in operation, or that obtains a final CEC permit to operate by

June 30, 2007. By today's decision, we provide for the possibility of a reliability exemption to the EPS that is very limited in scope. We also provide for the possibility of filing a petition for modification to obtain relief from the requirements of this decision in the event of extraordinary circumstances not contemplated by SB 1368 and this decision.

First, we allow for case-by-case exemptions to the EPS if the LSE can demonstrate that a long-term unspecified contract or commitment to a non-compliant specified powerplant is necessary to address system reliability concerns. As discussed in this decision, we believe that this type of exemption will probably not be needed, given the definition of covered procurements and other design aspects of the EPS. Nonetheless, we allow for the possibility of granting this limited exemption, on a case-by-case basis, in the event that unexpected reliability problems arise during implementation.

Second, we permit an LSE to file a petition for modification in the event of "extraordinary circumstances, catastrophic events, or threat of significant financial harm" that may arise during EPS implementation due to unforeseen circumstances not contemplated by SB 1368 and this decision. As in the case of a reliability exemption, our consideration of such a petition for modification comes with a heavy burden of proof on the LSE, as it must be based on extreme (and therefore highly unlikely) circumstances. Both the reliability exemption and the request for relief due to "extraordinary circumstances" must be pre-approved on a case-by-case basis by the Commission. As directed in this decision, LSE requests for pre-approval of a reliability exemption shall be made by application. LSE requests for relief from the requirements of this decision due to "extraordinary circumstances" shall be made by filing a petition for modification.

Additional exemptions from the EPS were proposed in this proceeding for (1) "small size" facilities, contracts or service territories, (2) research development and demonstration (RD&D) projects with the potential to develop a lower-emitting resource in the future, (3) gas-fired cogeneration and (4) case-by-case exemptions based on the cost of compliance. These recommendations were debated on both sides in parties' comments and legal briefs. For the reasons discussed in Section 4.8, we find that none of these exemptions are reasonable in light of the policy objectives and statutory requirements of SB 1368.[22] We also find that requiring QFs to comply with the GHG emissions performance standard is consistent with federal law, and conclude that we cannot grant QFs an exemption from the requirements of SB 1368 as some parties request.

In addition, a few parties recommend that we permit LSEs to obtain "offsets," whereby the LSE would have the option to offset emissions from a high-emitting baseload resource with GHG emissions reductions secured elsewhere to bring it into compliance with the EPS. Continuing with our appliance efficiency analogy, permitting the LSE to comply with the EPS in this manner would be akin to allowing customers to purchase refrigerators that do

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[22] As we discuss in this decision, the Legislature specifically directs that we not count CO_2 injected into geological formations (so as to prevent releases into the atmosphere) in the calculation of net emissions. Therefore, although we do not adopt a blanket RD&D exemption from the EPS, we do clarify how the LSE may apply for Commission pre-approval of covered procurements utilizing such CO_2 sequestration projects. In implementing §§ 8341(d)(2) and (5), we also clarify that we will determine EPS compliance for such covered procurements based on reasonably projected net emissions over the life of the facility, which recognizes that the sequestration project may become operational after the powerplant comes on line or the LSE enters into the contract. We will include in our review any emissions-related provisions that may be required through contract and/or permit conditions.

not meet the minimum level of efficiency for their own home, as long as they create offsetting efficiency savings in a neighbor's home, e.g., by changing out enough inefficient light bulbs with efficient ones (or paying a third party to do it). One party also suggests that we allow the LSE to average emissions rates across its entire procurement portfolio in demonstrating compliance with the standard.

We conclude that permitting LSEs to comply with the EPS through offsets or portfolio-averaging would compromise the very purpose articulated by this Commission and the Legislature for establishing an interim EPS in the first place. As discussed above, the EPS establishes a minimum level of acceptable GHG emissions performance for any baseload generation facility that represents a new long-term financial commitment to California. This serves a fundamentally different purpose, reflecting different policy objectives, than programs to reduce GHG emissions through a portfolio-wide cap, cap-and-trade programs or programs that permit LSEs to create or purchase offsets to meet an emissions cap or performance standard. As discussed in Section 5.4, the purpose of these programs is to provide varying degrees of compliance flexibility when the primary policy goal is to reduce the overall level of emissions generated through procurement activities.

The objective of the interim EPS, on the other hand, is to ensure that there is no "backsliding" as California transitions to a statewide GHG emissions cap. This objective cannot be accomplished if LSEs are permitted to comply with the standard by diluting the emissions from high-emitting powerplants through portfolio averaging, or by increasing the permissible level of emissions for

non-compliant powerplants through offsets or other means.[23] These options would only serve to disguise the types of problems that the EPS is designed to avoid, e.g., the high costs of future plant retrofits and reliability disruptions as it becomes increasingly difficult for these high-emitting facilities to comply with GHG emission regulations, such as the AB 32 declining cap on statewide GHG emissions.[24]

Moreover, as staff and many parties point out, a workable offsets program cannot be designed and implemented within the timeframe contemplated for an interim EPS, particularly in light of the SB 1368 statutory requirement that an enforceable EPS be put in place no later than February 1, 2007.

For these reasons, we do not permit offsets or portfolio averaging in the context of the adopted interim EPS. In the context of a load-based cap, however, we fully intend to evaluate a broad range of flexible compliance options as we proceed to implement the Procurement Incentive Framework during Phase 2 of this proceeding. Pursuant to AB 32, flexible compliance options will also be evaluated as California proceeds to implement the emissions limits required under that new law on a statewide basis.[25] As we stated in D.06-02-032, we will focus our efforts during Phase 2 on ensuring that the compliance options that we do permit under the Procurement Incentive Framework are credible, verifiable

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[23] For similar reasons, we also reject the notion of establishing "price caps" for complying with today's adopted EPS, as one party proposes. As discussed in Section 4.8.5, price caps would allow the LSE to build or enter into long-term contracts with high GHG-emitting plants without any reduction in those plants' emissions, which is not consistent with the purpose of establishing an interim EPS in the first place.

[24] AB 32, Cal. Health & Saf. Code § 38562(c).

[25] AB 32, Cal. Health & Saf. Code § 38561, § 38570.

and administratively feasible. During Phase 2, we intend to carefully explore the pros and cons of alternate proposals for offsets, trading, banking and borrowing and other compliance options before making our final determinations. Throughout the process, we will closely coordinate with CARB, the Governor's Climate Action Team as well as other state, regional or federal agencies that are exploring design options for cap-and-trade programs.[26]

1.8. Demonstrating Compliance with the EPS

Attachment 2 presents a flowchart illustrating how the EPS will be applied under today's adopted rules, consistent with SB 1368. We take a gateway screen approach, as recommended by Commission staff and all the parties to this proceeding. This approach is consistent with the intent of SB 1368, which directs us to look to the "design and the intended use" of the powerplant under § 8340(a). Moreover, as staff and the parties point out, a gateway screen approach is the most practicable and enforceable manner in which to determine EPS compliance.

As illustrated in Attachment 2, this approach applies a series of questions/criteria to first establish whether or not the LSE's financial commitment represents a covered procurement subject to the EPS. If it is, then the commitment is screened to ensure that it meets the performance level of the standard, e.g., that the associated GHG emissions rate does not exceed 1,100 lbs of CO_2 per MWh. Once the financial commitment successfully passes through the gateway screen, the LSE has demonstrated EPS compliance for that particular

[26] D.06-02-032, p. 44.

commitment. Ongoing Commission review or monitoring of the facilities underlying that commitment is not required.

We also describe in today's decision the procedures by which an LSE demonstrates compliance with this gateway screening process. Currently, Southern California Edison (SCE), San Diego Gas & Electric Company (SDG&E) and Pacific Gas and Electric Company (PG&E) bring all power purchase contracts with terms of five years or longer before this Commission for review and pre-approval by filing either an advice letter or application. As discussed in Section 5.1, we utilize these existing procedural vehicles for reviewing and pre-approving PG&E, SCE and SDG&E's covered procurements with respect to EPS compliance.

On the other hand, we do not currently require electric service providers, community choice aggregators or the small electrical corporations to submit procurement plans or power purchase contracts to the Commission for pre-approval. For these entities, we establish today an annual advice letter filing by which they can attest "after-the-fact" that they are in compliance with the EPS. They can also request Commission pre-approval of covered procurements as EPS-compliant (but are not required to) by advice letter.

In today's decision, we also clarify how to determine whether contracts that have a term of less than five years are "linked" and therefore should be treated as a single contract for the purpose of applying our adopted EPS rules. . In addition, we clarify the documentation requirements for all LSE compliance submittals, and approve the showings of "alternative compliance" by multi-jurisdictional electrical corporations pursuant to § 8341(d)(9).

2. Procedural Background

On October 6, 2005, we issued a Policy Statement on GHG Performance Standards (GHG Policy Statement) stating our intent to investigate the integration of GHG emissions standards into Commission procurement policies, including the Procurement Incentive Framework being developed in R.04-04-003.[27]

On February 16, 2006, we issued D.06-02-032 in R.04-04-003. In that decision, we adopted a load-based GHG emissions cap as the cornerstone of our Procurement Incentive Framework, noting that: "[e]stablishing a GHG cap is consistent with the Governor's objectives for climate change policy, as well as our own GHG Policy Statement."[28] Under a load-based cap, the LSEs would be subject to GHG emission limits for all resources procured to serve their load, no matter from what source, including imports. We made a number of preliminary determinations in D.06-02-032 to guide the next steps in implementing a load-based cap, but left most of the design details to a subsequent implementation phase.

On April 17, 2006, we opened this rulemaking to implement the load-based cap under our Procurement Incentive Framework and to examine the integration of GHG emission performance standards into procurement policies. We identified Phase 1 of this rulemaking as the forum for considering the following threshold issues:[29]

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[27] A copy of the GHG Policy Statement is included in Attachment 2 of the April 17, 2006 *Order Instituting Rulemaking* in this proceeding.

[28] D.06-02-032, *mimeo.*, p. 16.

[29] *Assigned Commissioner's Ruling: Phase 1 Scoping Memo and Notice of Workshop on Interim Greenhouse Gas Emissions Performance Standard*, June 1, 2006. (June 1, 2006 ACR.)

(a) Should the Commission adopt an interim GHG emissions performance standard to guide electric procurement decisions while it takes the necessary steps to fully implement D.06-02-032?

(b) If the Commission elects to adopt such a standard, how should it be designed and implemented so that it can be put in place quickly to serve this purpose?

The Assigned Commissioner proceeded to solicit pre-workshop comments on these issues, and staff of the Division of Strategic Planning ("staff" or "Commission staff") held a three-day workshop on June 21-23, 2006 to obtain further input from interested parties before formulating preliminary recommendations to the Commission.[30] Over 80 individuals, representing approximately 50 different stakeholders, attended one or more days of the workshop. Staff's preliminary recommendations were presented in the *Draft Workshop Report: Interim Emissions Performance Standard Program Framework* ("draft report"), which was issued for comment on August 21, 2006.

On September 29, 2006, Governor Schwarzenegger signed SB 1368 into law. Among other things, SB 1368 directs this Commission to establish a GHG emission performance standard through a rulemaking proceeding by February 1, 2007. It also specifies certain design elements of the GHG performance standard and associated definitions. The full text of SB 1368 is presented in Attachment 3.

Taking into consideration parties' comments on the draft report as well as the newly enacted provisions of SB 1368, staff issued its Phase 1

[30] The workshop was facilitated by Richard Cowart from the Regulatory Assistance Project, as a consultant to the Division of Strategic Planning.

recommendations in the *Final Workshop Report: Interim Emissions Performance Standard Program Framework* ("final report") on October 2, 2006.[31]

On October 5, 2006, we designated this rulemaking as the procedural forum for implementing SB 1368. The Commission also amended the list of respondents in order to encompass a broader group of LSEs, consistent with the definition of that term in SB 1368.[32] On that same day, the Assigned Commissioner amended the Phase 1 scoping memo to reflect these changes. The Phase 1 comment period was also extended to provide opportunity for respondents and interested parties to file written comments/legal briefs on all Phase 1 issues in the context of SB 1368, prior to our issuance of a draft decision.[33]

Over thirty-five parties submitted one or more sets of written comments or legal briefs during Phase 1. Attachment 4 lists the organizations that jointly or individually filed legal briefs, pre-workshop, post-workshop and/or final comments in Phase 1.

As required by SB 1368, we have consulted with the California Independent System Operator (ISO), CARB and CEC in designing the interim GHG emissions performance standard.[34] Consistent with our intent to work collaboratively with these agencies in this rulemaking, Commission staff and the assigned Administrative Law Judge (ALJ) met informally with staff from the

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[31] Staff's draft and final reports, along with other workshop-related materials are posted on the Commission's website at http://www.cpuc.ca.gov/static/energy/electric/climate+change.

[32] See *Order Amending Order Instituting Rulemaking*, October 5, 2006.

[33] *Assigned Commissioner's Ruling: Phase 1 Amended Scoping Memo and Request for Comments on Final Staff Recommendations*, October 5, 2006. (October 5, 2006 ACR.)

[34] § 8341 (d)(1) and (6).

CEC, CARB and the California ISO in order to brief them on the content of the staff recommendations, controversial issues raised in comments from the parties, and likely resolution of these issues in this decision. Commission staff also sought feedback during these meetings from collaborative agency staff. These meetings took place in October and November 2006, and additional consultation occurred in January 2007 prior to final adoption of the EPS in the form of informal meetings and written exchange.

3. Context and Policy Objectives

As discussed above, the Commission's GHG Policy Statement provided the Commission's initial policy context for consideration of an EPS in this rulemaking, while SB 1368 now also provides the statutory context. The principles and objectives articulated in each are nearly identical.[35] Both observe that California will need to rely on clean and efficient fossil-fired generation to the extent that energy efficiency and renewable resources are unable to satisfy increasing energy and capacity needs, consistent with the policies of the Energy Action Plan (EAP).[36] In addition, the Commission's GHG Policy Statement and SB 1368 recognize that:

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[35] See GHG Policy Statement, pp. 1-2 and SB 1368, Section 1, (a)-(l).

[36] The EAP adopted in May 2003 (and augmented by the October 2005 EAP II implementation roadmap) sets forth a blueprint for achieving the state's overall goal of adequate, reliable, and reasonably priced electrical power and natural gas supplies. Among other things, the EAP identifies the following "loading order" of energy resources that guides decisions made by this Commission and the CEC: (1) conservation and energy efficiency first, in order to minimize increases in electricity and natural gas demand, (2) renewables and distributed generation second, in recognition that new generation is both desirable and necessary, and lastly (3) clean and efficient fossil generation to the extent that (1) and (2) are not sufficient to meet California's energy needs.

(1) California's investor-owned utilities are currently making new long-term financial commitments to electrical generating resources that will have major impacts on GHG emissions for many years to come.

(2) It is vital to reduce California's exposure to costs associated with future federal regulation of GHG emissions.

(3) A GHG emissions performance standard for new long-term financial commitments to electrical generating resources will reduce potential financial risk to California consumers for future pollution-control costs.

(4) A GHG emissions performance standard for new long-term financial commitments to electric generating resources will reduce potential exposure of California consumers to future reliability problems in electricity supplies.

(5) The establishment of a policy to reduce emissions of greenhouse gases, including an emissions performance standard for all procurement of electricity by LSEs, is a logical and necessary next step to meet the goals of the EAP and the Governor's goals for reduction of emissions of greenhouse gases, and

(6) As the largest electricity consumer in the region, California has an obligation to provide clear guidance on performance standards for procurement of electricity by LSEs.

As articulated above, the primary objective of an EPS is to reduce California's exposure to the compliance costs associated with future GHG emissions (state and federal) and associated future reliability problems in electricity supplies. To meet this objective, an EPS functions similar to an appliance efficiency standard by ensuring that an LSE does not enter into long-term financial commitments with high-emitting baseload resources in the first place. For example, if a consumer wants to purchase a new refrigerator in California, he or she has a variety of models to choose from — each with a different upfront purchase price, operating efficiency and associated cost per

kWh to run, and design. However, at a minimum, each refrigerator must meet the threshold for appliance efficiency established by the standard. Similarly, SB 1368 establishes a minimum threshold of performance for any baseload generation facility that represents a new long-term financial commitment entered into by entities providing power to California ratepayers.

Some parties argue that our current oversight of utility resource planning is sufficient to achieve the Commission's procurement objectives, and therefore an EPS is not needed. In particular, San Diego Gas & Electric Company and Southern California Gas Company (SDG&E/SoCalGas) argue that the EAP "loading order" priorities and RPS program requirements render an interim EPS unnecessary.[37] We disagree. While loading order priorities and RPS requirements may reduce the overall size of the procurement needs to be filled by fossil-fired baseload generation, they do not establish safeguards against the risks associated with long-term procurement commitments to high GHG-emitting fossil-fired generation facilities. In fact, the EPS specifically addresses the last critical element of the EAP loading order, which prioritizes clean, efficient fossil generation.

Nor does the use of a GHG adder in the utility procurement process serve to adequately protect California ratepayers from these risks, as some parties suggest. The GHG adder, which assigns a $/ton cost to GHG emissions, is used

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[37] *Post-Workshop Comments of SDG&E/SoCalGas,* June 27, 2006, p. 2. See the footnote above for a description of the EAP loading order. In addition, by law, electricity production from eligible renewable energy resources must equal at least 20% of the total electricity sold to retail customers in California per year by December 31, 2010. (SB 107, Stats. 2006, ch. 464.) The RPS program was established by this Commission to implement these requirements, and RPS-related issues are addressed in R.06-02-012 and R.06-05-027.

to reflect one factor among many for utility competitive procurement and not as a regulatory standard. While the GHG adder would make procuring electricity from high-GHG emitting resources more expensive, thereby serving as a disincentive, it would still allow LSEs to procure from the dirtiest resources in some cases. The use of the GHG adder, therefore, could still result in a significant number of new long-term financial commitments with powerplants emitting GHGs that far exceed the EPS—an outcome that this Commission and the Legislature recognize would pose substantial financial and reliability risk to California ratepayers.[38] In contrast, the interim EPS sends clear direction that California has "raised the bar" for the GHG emissions performance of new long-term commitments with baseload generation serving California as we transition to a statewide, load-based GHG emissions cap.

It is within this context that we turn to the specific design and implementation of an interim EPS. As discussed in the Assigned Commissioner's scoping memo, our focus today is to adopt an interim standard that will serve as a near-term bridge to the load-based GHG cap adopted under

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[38] This can occur under the following type (or combination) of circumstances: (1) the level of upfront investment costs or power purchase contract prices associated with a high GHG-emitting powerplant are low relative to the discounted stream of emission-related costs captured by the $/ton GHG adder, (2) the operating and fuel costs of the high GHG-emitting powerplant are significantly lower than those of an EPS-compliant alternative, and/or (3) the upfront costs or power purchase prices associated with an EPS-compliant alternative are significantly higher than those of the high GHG-emitting powerplant, even if the operating or fuel costs are relatively low. There is no way to ensure through the use of a $/ton GHG adder (even one that is higher than the current level) that all long-term commitments to baseload generation facilities that emit above a certain performance threshold will be precluded, since each calculation will depend on variables unique to the type of alternatives analyzed and on assumptions that may vary

Footnote continued on next page

the Commission's Procurement Incentive Framework.[39] This focus is consistent with SB 1368, which directs the Commission to "reevaluate and continue, modify, or replace" the GHG performance standard adopted pursuant to the new law when "an enforceable" GHG emissions limit is established and in operation that is applicable to LSEs.[40] Consistent with the provisions of SB 1368, we will reevaluate the interim standard through a rulemaking proceeding and in consultation with the CEC and CARB.

Therefore, today's decision focuses on the most appropriate design parameters for an interim EPS, rather than a permanent one. SB 1368 also requires that the standard be established no later than February 1, 2007 and be enforced immediately upon its establishment.[41] Accordingly, we will consider the various Phase 1 proposals in the context of this implementation timeframe.

Our overall objective is to design an interim performance standard that focuses on new long-term financial commitments to electrical generating resources that will have major impacts on GHG emissions for many years to come. This enables us to prevent major LSE procurement "backsliding" that will make future GHG reductions more difficult. In this way, we can accomplish the key objective for the EPS, namely, to minimize the risk of new financial commitments that pose the greatest risk of raising future compliance costs to

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significantly over time (e.g., fuel prices, construction costs, contract prices or discount rates).

[39] June 1, 2006 ACR, p. 1.

[40] § 8341(g).

[41] § 8341(d).

ratepayers and of causing future reliability disruptions in electricity supplies.[42] We also seek to develop an EPS that is relatively simple to administer and implement, and that will keep the analysis and application of the standard to various resources transparent.

4. Interim GHG Emissions Performance Standard: Design and Implementation

In the discussion that follows, we use the terms "interim GHG emissions performance standard," "standard," and "emissions performance standard" (or "EPS") interchangeably. We use the term "greenhouse gases" or "GHG" to refer to the types of emissions that will ultimately need to be included in the strategies to mitigate climate change. More specifically, this term refers to the six gases listed under Section 42801.1(h) of the California Health and Safety Code: (1) carbon dioxide (CO_2), (2) methane, (3) nitrous oxide, (4) hydrofluorocarbons, (5) perfluorocarbons, and (6) sulfur hexafluoride, consistent with the definition contained in SB 1368.[43]

While the new law refers to all six of the gases listed above in its definition of greenhouse gases, it also establishes a deadline of February 1, 2007 for enforcement of the EPS. We do not have sufficient data to create and enforce a GHG emissions performance standard beginning February 1, 2007 that covers all of the gases. Currently, utility data for the CCGT standard contemplated by SB 1368 is only reported to the California Climate Action Registry for the largest GHG emissions source by volume, namely, for CO_2. This is also the only GHG consistently reported by electrical corporations on an entity-wide basis at this

[42] See Section 1 of SB 1368, subsections (i) and (j).

[43] § 8340(g).

time.[44] The Commission will seek to identify options to integrate reporting of all GHGs in the future. However, in order to meet the February 1, 2007 statutory deadline, we limit today's adopted EPS to CO_2 emissions as it is the most pervasive of the GHGs, and the most widely reported and verified of the GHGs at this time.

We may reevaluate how the EPS can be expanded to include some or all of the additional gases listed above when sufficient knowledge and data becomes available on their respective emission levels from generation sources, and when that information can be translated into an enforceable EPS.[45]

SB 1368 specifies several design and implementation parameters for the interim EPS, and in the following sections we highlight the relevant language from the statute. For each design or implementation issue, we briefly summarize the staff proposal as well as the chief points of contention reflected in parties' comments before presenting our conclusions. As usual in such proceedings, the record is voluminous, and therefore we do not summarize every nuance in individual positions.

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[44] In particular, as part of the California Climate Action Registry, Pacific Gas and Electric Company (PG&E) has only started to report the other gases beginning in 2006, and SDG&E and Southern California Edison Company (SCE) will start reporting them beginning in 2007.

[45] As discussed in Section 4.10 below, we consider representative emissions of both methane and CO_2 for a much more limited purpose, namely to show that generating electricity from biomass, biogas or landfill energy can actually *reduce* the net GHG emissions associated with the disposal of society's waste and residue materials, and therefore we should pre-approve biomass generation as complying with the EPS.

4.1. Entities Subject to the EPS

Prior to the passage of SB 1368, there was some debate on both policy and legal grounds as to which entities should be subject to the EPS. All parties now conclude, as we do, that SB 1368 has laid this debate to rest by directing that this Commission develop an EPS for LSEs and by specifically defining that term in the new law. Consistent with that definition, the EPS we adopt today will apply to every electrical corporation, electric service provider, or community choice aggregator serving end-use customers in the state.[46] Throughout this decision, we use the term "LSE" to refer collectively to these entities.

4.2. Types of Generation and Financial Commitments Subject to the EPS ("Covered Procurements")

SB 1368 describes what types of generation and financial commitments will be subject to the EPS ("covered procurements"). Under SB 1368, the EPS applies to baseload generation, but the requirement to comply with it is triggered only if there is a "long-term financial commitment" by an LSE.[47] There are two kinds of "long-term financial commitments" under SB 1368. For LSE-owned powerplants a long-term financial commitment occurs when there is a "new ownership investment." For baseload generation procured under contract, there is a "long-term financial commitment" when the LSE enters into "a new or renewed contract with a term of five or more years."[48] For purposes of our

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[46] § 8340(c), (d), (e), and (h). To date, no community choice aggregator has been formed, though interest has been expressed in a number of localities.

[47] § 8341(a), first sentence.

[48] § 8340(j).

discussion here, we will call a long-term financial commitment for baseload generation a "covered procurement."

SB 1368 defines baseload generation as "electricity generation from a powerplant that is designed and intended to provide electricity at an annualized plant capacity factor of at least 60 percent."[49] The new law defines the terms "powerplant" and "plant capacity factor" for this purpose, as follows:[50]

- "Powerplant" means a facility for the generation of electricity, and includes one or more generating units at the same location.
- "Plant capacity factor" means the ratio of the electricity produced during a given time period, measured in kilowatt hours to the electricity the unit could have produced if it had been operated at its rated capacity during that period, expressed in kilowatt hours.

Finally, the statute also states that "all combined-cycle natural gas powerplants that are in operation, or that have an Energy Commission final permit decision to operate as of June 30, 2007, shall be deemed to be in compliance" with the EPS.[51]

In the following sections, we discuss the issues raised in parties' comments with respect to covered procurements.

4.2.1. Capacity Factor of Covered Procurements

In their comments, Green Power Institute (GPI) recommends that the Commission adopt a 50% capacity factor threshold in order to include high-use intermediate and shaping facilities in the definition of covered procurements. We prefer not to go beyond what the Legislature intended and, therefore, the

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[49] § 8340(a).

[50] § 8340 (m) and (l), respectively.

interim EPS will apply to baseload generation that is designed and intended to provide electricity at an annualized plant capacity factor of at least 60 percent. We note that staff and most parties to this proceeding recommended a 60% capacity factor threshold for covered procurements, even prior to the passage of SB 1368, based on the data submitted in Phase 1 of this proceeding. That data illustrates that a 60% capacity factor captures an estimated 78% of the incremental procurement needs in 2012 for PG&E, SDG&E and SCE combined, and would capture 72% of CO_2 emissions associated with those procurement needs.[52]

4.2.2. Renewal Contracts

Prior to the passage of SB 1368, parties were divided on the issue of whether contract renewals with existing baseload generating facilities should be subject to the EPS. The language of the statute is clear that new as well as renewal contracts having a term of five years or more represent a "new financial commitment," and therefore must comply with the EPS. Accordingly, we adopt the definition of new financial commitment contained in SB 1368 for the interim EPS.

4.2.3. Retained Baseload Generation

Retained baseload generation refers to the existing baseload facilities (e.g., coal, nuclear or natural gas-fired plants) owned by the LSE and used to serve its

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[51] § 8341(d)(1).

[52] These figures represent the percentage of annual CO_2 associated with the utilities' incremental procurement needs in 2012 that would be captured by new commitments to facilities operating at a 60% capacity factor (based on heat rates in the 7000-8600 range). See Response #3 to the ALJ's June 21, 2006 data request posted at www.cpuc.ca.gov/static/energy/electric/climate+change.

load. As several parties note in their comments, under staff's proposal, retained baseload generation does not enter into the type of commitments that would trigger the EPS review, unless the LSE makes major plant renovations or sells that power under a contract of five years or more with another LSE. Two major questions were raised by parties with respect to retained baseload generation:

(1) Should the LSE's retained baseload facilities be subject to the EPS as a general principle—irrespective of whether the LSE makes a new financial investment in the plant?

(2) Should the utility's new investments (plant alterations) to retained baseload generation trigger application of the EPS, and if so, what types of plant alterations?

We discuss each of these issues below.

4.2.3.1. Retained Generation without New Utility Investment

Constellation Energy Group (Constellation), Alliance for Retail Energy Markets (AReM) and a number of individual electric service providers propose that the Commission develop a mechanism to subject all of the utility's retained baseload generation to the EPS, either immediately upon implementation of the EPS or periodically thereafter.[53] These parties contend that not doing so creates a *de facto* loophole in the establishment of an EPS, which violates the goals and statutory language of SB 1368.

[53] AReM's membership includes a number of electric service provider respondents in this proceeding: APS Energy Services Company, Inc.; Commerce Energy, Inc.; Constellation Newenergy, Inc.; Sempra Energy Solutions; and Strategic Energy, LLC.

In particular, Constellation et al.[54] argue that the reference in § 8341(d)(1) to "all baseload generation of load-serving entities" precludes any disparate treatment for utility-owned generation and non-utility owned generation. They believe that such disparate treatment exists if the EPS is triggered for all contracts of five years or longer with non-utility owned existing baseload generation (with or without major renovations), but only for utility-owned existing baseload generation if and when it undergoes major renovations. Accordingly, they recommend that the Commission require the utilities to demonstrate compliance with the EPS upon renewal of any "rate recovery contract" for its retained baseload generation, meaning any time the utility seeks rate modifications or submits procurement plans supporting existing utility-owned assets.

Constellation et al.'s reading of the statute is incorrect. As discussed above, the plain language of SB 1368 provides clear direction as to what triggers the requirement to apply the EPS: Sections 8341(a), (b)(1), and (b)(2) provide that the EPS shall apply to all baseload generation *in the event that the compliance requirement is triggered by a "long-term financial commitment"* as defined in § 8340(j). And that subsection contains an asymmetric definition of what constitutes a "long-term financial commitment" for utility-owned generation and contracted-for generation.

In their comments, Constellation et al. take the phrase "all baseload generation of load-serving entities" in § 8341(d)(1) out of context with respect to

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[54] See *Joint Comments of Constellation Newenergy, Inc., Constellation Energy Commodities Group, Inc., Constellation Generation Group, LLC, NRC Energy, Inc., Mirant California, LLC, Mirant Delta, LLC, Mirant Potrero, LLC and Alliance for Retail Energy Markets on Final Workshop Report,* October 18, 2006, p. 7.

the rest of the statute. In particular, that phrase is used in the context of the Legislature's direction for when ("on or before February 1, 2007") the Commission must establish and EPS and at what rate of emissions ("no higher than the rate of emissions of greenhouse gases for combined-cycle natural gas baseload generation."). To interpret this phrase to mean that the Legislature intended to subject utility-owned retained baseload generation to the EPS, with or without a "new ownership investment" as required by § 8341(a)(1), would contradict the language of §§ 8341(a), (b)(1), (b)(2) and § 8340(j), or render it meaningless.

Moreover, the only way to give the meaning to § 8340(j) that Constellation et al. suggest would be to assume, as these parties do, that a "renewed contract" under the definition of "long-term financial commitment" in § 8340(j) includes the type of "rate recovery contract" with existing utility-owned baseload generation facilities that these parties describe in their comments. First of all, it is doubtful that the kinds of regulatory measures that Constellation et al. describe are contracts as that term is ordinarily understood. Even if they are "contracts," they are not the kind of contracts the Legislature was describing in § 8340(j). Contracts for the procurement of baseload generation and "contracts" for the recovery of costs associated with generation are two separate things. The statute only applies to the former. Furthermore, Constellation et al. do not suggest how one would determine whether any particular "rate recovery contract" is for a period of less or more than five years.

Nothing in the statutory language or legislative history reflects this intent or direction.[55] In fact, in the Senate Committee analyses of SB 1368 the term "long term contract" is consistently referred to in the context of the procurement contracts covered under the Commission's procurement planning process, which do not apply to utility-retained generation.[56]

Finally, contrary to Constellation et al.'s assertions, we believe that excluding utility-owned retained generation from EPS-covered procurements (unless the electricity sold to another LSE under a long-term contract or the powerplant is renovated as that term is defined in this decision) is fully consistent with the principles and objectives for an interim EPS articulated by the Legislature and this Commission. As discussed in Section 3 above, both the Legislature and this Commission have recognized that California utilities are "currently making new long-term financial commitments to electrical generating resources that will have major impacts on GHG emissions for many years to come," and have concluded that an EPS "for new long-term financial commitments to electrical generating resources will reduce potential financial risk to California consumers for future pollution-control costs."[57] Accordingly, the definition of covered procurements that we adopt today focuses on

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[55] Throughout this decision, our references to "legislative history" refer to the history of the bill as it was amended in the Legislature, the Committee Analyses at each reading (available at www.leginfo.ca.gov), as well as the public Committee hearing tapes available on SB 1368, all of which we have carefully reviewed.

[56] See, for example, Senate Third Reading on SB 1368 (as Amended August 21, 2006 and as amended August 30, 206), p. F: *"What is a long-term contract?"*

[57] See GHG Policy Statement, pp. 1-2 and SB 1368, Section 1, (a)-(l).

preventing "backsliding" through new LSE procurement decisions that will make future GHG reductions more difficult.

Constellation et al. fundamentally disagree with these stated objectives for an EPS. Rather than focus on new financial commitments, they recommend that the EPS scope be broadened to apply to the LSE's existing fleet of baseload generation facilities that are used to meet the LSE's load. However, this is not the purpose of the EPS, as discussed above. In effect, the definition that Constellation et al. recommend would subject the millions of dollars in the LSE's already-built facilities to a standard that is being developed to prevent backsliding in LSE decisions made for future investments and avoid the additional financial and reliability risks that such backsliding would create.

For the above reasons, we reject this recommendation. We will adopt what the Legislature intended by using the same definitions for covered procurements as in the statute. As discussed above, § 8340(g) defines "long-term financial commitment" as "either a new ownership investment in baseload generation or a new or renewed contract with a term of five or more years, which includes procurement of baseload generation."

In its opening comments to the Proposed Decision, SCE argues that the definition of "covered procurements" might result in unconstitutionally impairing a contract that it has with its co-tenants concerning maintenance of the Four Corners Project. SCE does not state that the EPS rule as currently written will prevent it from complying with its contractual obligations, only that it may. Nor does it provide us with a copy of the contract. In short, this record does not establish whether the EPS rule as written will make it impossible for SCE to comply with its contractual obligations, and if so whether that would constitute an unconstitutional impairment of contract. Furthermore, SCE's proposed

solution is to grant generic relief, rather than relief for the specific plant where SCE says it has problems. Accordingly, we see no reason to grant SCE's requested relief at this time. If SCE anticipates that the EPS will prevent it from complying with its contractual obligations at Four Corners, it should file an application or petition for modification, together with adequate supporting information, documentation, and analysis, and request appropriate relief.

4.2.3.2. Retained Generation with New Utility Investment

SCE interprets SB 1368 to exclude from EPS review any new utility investment in retained generation. Specifically, in its comments on the draft report, SCE argues that the definition of "long term financial commitment" provided by SB 1368 is limited to an "'investment in baseload generation' that is also a 'new ownership' interest."[58] To support this reading SCE argues that the absence of a comma between "new" and "ownership" necessarily means that "new" modifies "ownership" and not "investment." Under SCE's reading, therefore, an investment in baseload generation that is part of an "existing ownership interest," such as repowering or otherwise renovating utility retained generation, would not have to comply with the EPS. SCE bases its grammatical argument on rules outlined in *The Gregg Reference Manual.*

SCE's assertion that the absence of a comma mandates its reading is incorrect. According to several other sources of grammatical usage, including

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[58] *Reply Comments of SCE on the Draft Workshop* Report, September 15, 2006, p. 4. In their comments SCE equates the word "investment" from the statute with the word "interest." Had the Legislature used the word "interest" instead of "investment" it would support SCE's reading. The Legislature, however, chose to use "investment" and not "interest," and therefore did not limit the application of the EPS to new ownership investments that *also* represent a new ownership interest.

The Chicago Manual of Style and *The Random House Handbook*, a comma should be inserted between adjectives when they both modify the same noun in the exact same way.[59] Thus, the phrase "nutritious, delicious dinner" has a comma in it, because both "nutritious" and "delicious" modify the word "dinner." Where a comma is required, the two adjectives "can be reversed without affecting their meaning"[60] Thus, a "nutritious, delicious dinner" is readily understood to mean the same thing as a "delicious, nutritious dinner."

Accordingly, a comma would only be necessary if one could substitute the phrase "ownership, new investment" for the phrase "new, ownership investment" without affecting the meaning. However, changing the order of the words does affect the meaning; indeed it is not easy to comprehend what the phrase "ownership, new investment" would mean if it had appeared in the statute. Furthermore, these authorities establish that no comma is required where the first adjective modifies the idea expressed by the combination of the second adjective and the noun.[61] In these cases, the second adjective pairs with the noun, and the two together are then modified by the first adjective. Thus, no comma is required when we talk about the "typical American meal" or "traditional political institutions." In the first instance the word "typical" modifies the phrase "American meal"; in the second, "traditional" modifies "political institutions." Similarly, here the word "new" modifies the phrase

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[59] Bergen Evans, *A Dictionary of Contemporary American Usage*, Random House (New York, © 1957).

[60] Frederick Crews, *Random House Handbook*, 4th Ed. Random House (New York, © 1984).

[61] *The Chicago Manual of Style*, 14th Ed., The University of Chicago Press (Chicago, © 1993).

"ownership investment" and no comma is required to express that meaning. Therefore, SCE's argument here is simply wrong.

In its comments on the final report, SCE adds several more arguments contending that SB 1368's definition of "long-term financial commitments" should be read to exclude significant renovations or repowering of utility retained generation. In particular, SCE argues that "the purpose of SB 1368 is to encourage new long-term financial commitments to zero- and low-carbon generating resources - not to prohibit other long-term financial commitments, such as major renovations of existing facilities as staff would do."[62] In support of this argument SCE cites SB 1368 § 1(e) which states that "new long-term financial commitments to zero- or low-carbon generating resources should be encouraged."

We read this statement of intent to apply most directly to § 8341(b)(6), which provides for an increased return on investment for third parties selling "zero- or low-carbon generation" to electrical corporations. Not only does SCE misunderstand that "encourage" as it appears in SB 1368 specifically refers to § 8341(b)(6), but SCE also ignores the fact that the statute explicitly prohibits "load-serving entities from entering into long-term financial commitments unless any baseload generation" supplied under that commitment complies with the EPS established by the commission. [§ 8341(a).] Thus, SCE's reading is contrary to the plain language of the statute, since § 8341(a) clearly *prohibits* LSE's from entering into long-term financial commitments that fail to comply with the EPS.

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[62] *Opening Comments of SCE on Final Staff Workshop Report,* October 18, 2006, p. 3, emphasis in the original.

SCE next contends that the legislative history supports its view that "SB 1368 does not apply to major renovations of exiting facilities where the ownership of the facility has not changed."[63] As SCE notes, on June 22, 2006 the definition of "long-term financial commitment" was amended and the word "new" was inserted in front of "ownership investment." SCE argues that this change clearly demonstrates the Legislature's intent to include only "new ownership investments," as in acquisitions, and to exclude "existing ownership investments," as in renovations or repowering of utility retained generation.

We disagree. Before "new" was added to the definition, "ownership investment" could have been read to include *all* utility retained generation, including those facilities built, repowered and renovated prior to the statute's effective date. This is because "investment" can mean either: the sum which is currently invested; or, the placing or outlay of money for income or profit.[64] Both meanings are commonly used, and we must assume that the Legislature was aware of this potential ambiguity. Absent the word "new" it is unclear as to whether "ownership investment" means: 1) the sum which is currently invested, as in all utility retained generation; or 2) the outlay of money for baseload generation, as in new commitments of money such as repowering and other major renovations to existing facilities. We conclude that the Legislature added "new" to preclude the broader interpretation that would include all utility retained generation and not, as SCE contends to exclude new investments in utility retained generation.

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[63] *Ibid.*, p. 5.

[64] *Merriam-Webster's Collegiate Dictionary*, 10th Ed. (2001), p. 615.

In its comments to the Proposed Decision, SCE replies that the word "ownership" is unnecessary if the legislature intended the phrase "new ownership investment" to include repowering and investments intended to extend the life of the plant by five years or more. Instead, SCE argues, the Legislature could have achieved the same result by requiring compliance for all "new investments." We disagree. By including the word "ownership" the Legislature clarified any ambiguity that would have otherwise existed between contracted for baseload generation and investments in baseload generation.

More importantly, SCE's reading would undermine the primary purpose of the EPS. One key precept in interpreting statutory language is that "all the rules of statutory construction are subservient to the one that legislative intent must prevail if it can be reasonably discovered in light of the intended purpose."[65] The Senate Floor Analysis noted: "The purpose of this bill is to prevent long-term investments in powerplants with GHG emissions in excess of those produced by a combined-cycle natural gas powerplant."[66] Here no distinction is drawn between different kind of investments, and we must, therefore, conclude that the Legislature intended to prevent those investments

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[65] *Ford & Vlahos* v. *ITT Commercial Finance Corp.*, (1993) 23 Cal. Rptr. 2d 175, 21 U.C.C. Rep. Serv. 2d (CBC) 1228 (App. 1st Dist.), as modified on denial of reh'g, (Oct. 20, 1993) and review granted and opinion superseded, 26 Cal. Rptr. 2d 475, 864 P.2d 1036 (Cal. 1993) and judgment rev'd on other grounds, 8 Cal. 4th 1220, 36 Cal. Rptr. 2d 464, 885 P.2d 877, 25 U.C.C. Rep. Serv. 2d (CBS) 630 (1994).

[66] See, Senate Rules Committee, Office of Senate Floor Analysis, August 30, 2006, page 6, posted at http://www.leginfo.ca.gov/pub/05-06/bill/sen/sb_1351-1400/sb_1368_cfa_20060831_111932_sen_floor.html.

made by owners with long-term effects, such as repowering and alterations intended to extend the life of the plant by five years or more.[67]

In sum, we concur with staff, Natural Resources Defense Council (NRDC), The Utility Reform Network (TURN), Union of Concerned Scientists (UCS), Western Resource Advocates (WRA) and others that the term "new ownership investment" under SB 1368 encompasses new LSE investments in retained baseload generation.

Several suggestions were presented in comments regarding when the EPS would be triggered for such new ownership investments. Under the staff proposal, repowering of an existing baseload facility would trigger the application of the EPS, in addition to other new financial commitments to baseload plant.[68] California Cogeneration Council (CCC) would add that LSE-owned generation be subject to the EPS whenever major equipment is replaced or added, and defines "added" to include the installation of air pollution control equipment. PG&E and SDG&E/SoCalGas recommend that the EPS be triggered for current retained generation (or once a new plant has

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[67] In its *Opening Comments on the Proposed Decision*, CMUA argues in support of SCE's reading and asserts that "in all cases, the words, phrases and sentences of SB 1368 evidence a legislative intent to trigger the EPS only when an LSE enters into a new legal relationship involving the procurement of baseload generation." Opening Comments, p. 7. CMUA cites no persuasive authority in reaching this conclusion. Furthermore, so limiting the application of the EPS would undermine the Legislature's intent as discussed above.

[68] Repowering generally refers to the construction of new generating units at an existing site and the complete or partial dismantling of existing generation units at the same site. Existing units are not always entirely retired or dismantled. Generators can often re-use the busbar/transformer arrays, transmission tap lines to grid interconnect, water and gas supply lines and cooling structures during repowering.

demonstrated compliance with the EPS) only if the powerplant is repowered or upgraded in such a way that its design capacity has increased.[69]

In their joint comments on the draft report, NRDC, TURN, UCS and WRA recommend that the Commission consider all major refurbishments, in addition to repowering, to represent new ownership investments that would be subject to the standard. In determining what constitutes a major refurbishment, these parties recommend that the Commission set a threshold for the EPS based on total dollars and total greenhouse gas emissions at stake, but do not propose specific levels for this threshold. More generally, they suggest that the refurbishment be subject to the EPS if it is intended to extend plant life by more than five years and if the plant is designed and intended to operate at a 60 percent capacity factor or greater.

Among these suggestions, we are looking for the best and most workable approach to identifying changes in an existing powerplant that would increase the expected level of GHG emissions from the facility over the long-term. This is not accomplished by requiring that every replacement of equipment or addition of pollution control equipment should trigger the EPS, as CCC suggests. Even after such changes, the plant and its operation may remain essentially unchanged. More importantly, this approach could reduce reliability as old parts are repaired rather than replaced.

We also believe it would be arbitrary to try to set a dollar level threshold for new ownership investments, as NRDC and others recommend. However, their suggestion that the EPS be triggered by refurbishments that significantly

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[69] *Opening Comments of PG&E on Draft Workshop Report*, September 8, 2006, p. 5. *Reply Comments of SDG&E/SoCalGas on Draft Workshop Report*, September 15, 2006, pp. 4-5.

extend the plant life does have merit. When coupled with the proposal by PG&E, SDG&E and SoCalGas, we think a workable definition of new ownership investments can be crafted.

Specifically, in addition to new baseload plant construction or the acquisition of new ownership interest in an existing plant owned by others, we will define "new ownership investments" to include any investment that is intended to extend the life of one or more units of an existing baseload powerplant for five years or more, or results in a net increase in the existing rated capacity of that powerplant. "Rated capacity" refers to the plant's maximum rated output under specific conditions designated by the manufacturer and usually indicated on a nameplate physically attached to the generator. New ownership investments will also include any investment made for the purpose of converting a non-baseload plant to a baseload plant (i.e., so that it is now designed and intended to provide electricity at an annualized plant capacity factor of 60 percent or greater).

We believe that the definition above covers "repowering" as the term is generally used in the industry, since the types of renovations normally undertaken during repowering (e.g., replacing one or more of the plant's existing turbine(s)) would significantly extend the life of the unit(s), increase the rated capacity of the powerplant, or both.) However, only those units in a multi-unit generating facility that are being added, replaced or altered must comply with

the EPS.[70] In any event, additional units may be considered new powerplants, as discussed in Section 4.2.4 below.

4.2.4. Definition of "Powerplant"

SB 1368 defines the term "powerplant" as "a facility for the generation of electricity, and includes one or more generating units at the same location."[71] We therefore use the terms "powerplant" and "facility" interchangeably in today's decision.

We read this language to mean that a powerplant may be comprised of one or more generating units at the same location; however, it does not necessarily follow that *all* of the units at the same location comprise a single powerplant (facility). For example, different resources or technologies could be generating power at the same location, e.g., a generating unit fueled with a renewable resource located in the same site as a fossil-fueled unit. We do not believe that the Legislature intended for the term "powerplant" to mean that these distinct and separate generating technologies and resources should be treated as a combined, single "powerplant" for the purpose of applying the EPS. To do so would effectively permit the blending of high-emitting resources with low- or zero-emitting resources simply due to the physical co-location of the generating units. This could lead to an absurd result where power stations are expanded in order to co-locate high emitting generating units with renewable or low-emitting CCGTs, in order to circumvent the EPS rule.

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[70] At the request of the assigned ALJ, interested parties commented on this definition in their October 27, 2006 reply comments. We note that those comments indicate general concurrence with the definition presented above.

[71] § 8340 (m).

To avoid this absurd result, we clarify that generating units utilizing different resources or technologies, no matter if they are at the same location or contracted for under the same purchase power agreement, must each be evaluated separately for the purpose of evaluating whether the resource operates as baseload generation and, if so, whether its emissions rate complies with the EPS.

In its comments on the Proposed Decision, IEP requests further clarification on how "units employing the same resource or technology and located at the same site (powerplant) should be treated: Is each unit to be treated as a 'facility' or 'source' or is the entire multi-unit powerplant the 'facility' or 'source?'[72] In effect, IEP requests us to further clarify the circumstances under which a "powerplant" is a facility comprised of more than one generating unit in applying the EPS rules.[73] The discussion above clarifies that if there is a generating unit that is fueled by a renewable resource at the same location as a fossil-fueled unit (i.e., two units that utilize different resources or technologies), we would apply the EPS as if each unit were a single-unit powerplant (or "facility"). The fact that both units happen to be at the same location is not a "sufficient" condition for treating them as a single powerplant, because doing so would lead to an absurd result.

However, as IEP's comments suggest, this clarification needs to be augmented to address situations when more than one generating unit utilizing

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[72] *Comments of the IEP on the Proposed Decision*, January 2, 2007, pp. 5-6.

[73] Under SB 1368, "powerplant" is defined as "a facility for the generation of electricity, and includes one *or more* generating units at the same location." (§ 8340(m), emphasis added.)

the same resource (fuel) or technology are at the same location—in other words, does this automatically mean that the two comprise a multi-unit "powerplant" for purposes of applying the EPS? For example, what if there are two generating units utilizing natural gas, one designed and intended to operate as a baseload unit and the other as a load-following unit with a capacity factor of significantly less than 60%? Or what if two baseload generating units at the same location (i.e., each designed and intended to operate at a 60% annualized capacity factor or greater), but one has an emissions rate higher than the EPS and the other significantly lower? In each of these situations, treating the two generating units as a single multi-unit powerplant could lead to absurd results that undermine the intent of SB 1368, such as the "blending" of high and low-emitting generating units to meet the standard (second example), or avoiding the EPS altogether by combining units with high and low-capacity factors to produce an average below the 60% capacity factor threshold (first example).

Accordingly, for the purpose of applying the EPS rule we further clarify that a powerplant is considered to be a generation facility comprised of more than one generating unit if: (1) the units are at the same location *and* (2) each unit utilizes the same resource (fuel) or technology, *and* (3) one or more of the units are operationally dependent on another.[74] This clarifies our EPS rules in a manner that avoids the absurd results discussed above, and addresses the issue raised by IEP.

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[74] For example, there are ten different 15 MW gas-fired units strung together utilizing a reciprocating generation technology to provide a total output capability of 150 MW, and you need to have one unit on to run any of the others. Or you may have a 100 MW CT comprised of a 10 MW quick-start unit and a 90 MW unit strung together, so that you could never get MWs 11 to 100 unless you have 0-10 on.

In its comments on the Proposed Decision, Constellation suggests that the EPS be applied at a "power block" level, rather at the individual unit level, using the California ISO's Resource ID listing of power blocks for this purpose.[75] However, as IEP points out in its comments, this approach has a practical limitation for contracts with planned new units, since the unit might not have a Resource ID at the time of contracting and EPS evaluation.[76] Moreover, it is unclear from the example that Constellation presents in its comments whether or not the Resource ID approach to aggregation could lead to the types of absurd results discussed above. Therefore, we reject this recommendation in favor of the clarification we present above in response to IEP's comments.

4.2.5. "Deemed-Compliant" Combined Cycle Natural Gas Powerplants

This brings us to the issue raised by staff's final recommendations, namely, the treatment of combined cycle natural gas powerplants deemed to be in compliance under § 8341(d)(1). We use the term "combined cycle gas turbine" (or "CCGT") powerplant to refer to a "combined cycle natural gas plant" defined in SB 1368.[77]

SB 1368 provides that all CCGT powerplants "that are in operation, or that have an Energy Commission final permit decision to operate as of June 30, 2007, shall be deemed to be in compliance with the greenhouse gases emission

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[75] *Comments of Constellation et al. on Draft Decision*, January 2, 2007, pp. 8-9.

[76] *Comments of the IEP on the Proposed Decision*, January 2, 2007, p. 6, footnote 10.

[77] Specifically, a CCGT powerplant refers to a powerplant that "employs a combination of one or more gas turbines and steam turbines in which electricity is produced in the steam turbine from otherwise lost waste heat exiting from one or more of the gas turbines." (§ 8340(b).)

performance standard."[78] Staff recommends that a powerplant deemed compliant pursuant to § 8341(d)(1) ("deemed-compliant CCGT powerplant") be required to demonstrate actual compliance upon repowering or upon the renewal of a power purchase contract of five years or more. PG&E, SDG&E/SoCalGas and others argue that this recommendation is inconsistent with the statutory language described above that essentially "grandfathers" these plants, thereby exempting them from the requirement to demonstrate compliance with the EPS.

The staff proposal would essentially apply the same standard of review for deemed compliant CCGT powerplants as for all other LSE retained generation.[79] As discussed in Section 4.2.3.2, SB 1368 requires that an LSE demonstrate compliance for all "new ownership investment" in retained generation, which we define as alterations intended to extend the life of one or more units of an existing baseload powerplant for five years or more, or result in a net increase in the existing rated capacity of the powerplant.

A CCGT powerplant that is *deemed* compliant does not have to demonstrate actual compliance with the adopted EPS standard, but is instead treated *as if* it met the EPS standard and is excused from making an affirmative

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[78] § 8341(d)(1). We conclude that the Legislature intended that the concept of "deemed compliance" be distinct from the concept of "compliance" generally. (Hereinafter, we will use the terms, "actual compliance" and "compliance" interchangeably.)

[79] We find no indication in SB 1368, or in its legislative history, that the Legislature intended that CCGT powerplants should lose their deemed-compliant status solely due to contract renewal. If the Legislature had intended to require that existing facilities demonstrate actual compliance upon contract renewal, instead of deeming the CCGT facilities themselves compliant, they could have stated so explicitly.

showing of compliance.[80] Reading § 8341(d)(1) to require that the same kind and scale of alterations, improvements, additions, or renovations that constitute "new ownership investment" would also trigger a requirement that deemed-compliant CCGT powerplants demonstrate actual compliance with the EPS, would render the § 8341(d)(1) deemed-compliant provision redundant as applied to utility-owned CCGT powerplants.

California courts have long observed the canon of statutory construction that when attempting to ascertain the meaning of a statute, "effect should be given...to the statute as a whole and to every word and clause thereof, leaving no part of the provision useless or deprived of meaning."[81] In order to give § 8340(j), (defining long term financial commitment to include new ownership investments), § 8341 (requiring that all long term financial commitments meet the EPS) and § 8341(d)(1) (deeming CCGTs compliant) their full effect with respect to utility-owned CCGTs in operation as of the date of implementation of the EPS (or that obtain a CEC permit as of June 30, 2007), we conclude that "new ownership investment" in retained generation cannot automatically trigger EPS review for deemed-compliant CCGT powerplants.

Another canon of statutory construction, however, requires us to avoid interpretations of law that would lead to an absurd result.[82] The purpose of SB 1368 would be thwarted if existing CCGT are deemed to be permanently in compliance regardless of any subsequent changes to the facilities. One could

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[80] The verb "deem" means "to treat something as if (1) it were really something else, or (2) it has qualities it doesn't have". *Black's Law Dictionary*, 7th Ed, at 424, West Publishing (St. Paul, Minnesota © 1999).

[81] *Gay Law Students Association* v. *Pac. Tel. & Tel. Co.*, (1979) 24 Cal.3d 458, 478.

argue that if units are added to an existing deemed-compliant CCGT powerplant – thereby increasing its capacity from 50 MW to 250 MW – the additional units are nevertheless "deemed compliant" and do not have to demonstrate actual compliance. Under this construction, an LSE or non-LSE owner could circumvent the EPS simply by adding units that are operationally dependent on one or more existing units within a previously deemed-compliant CCGT powerplant.[83] We should avoid construing the statute to achieve this absurd result. The deemed-compliant status is given to existing CCGT powerplants, and extending the exemption to units that did not exist at the time of the passage of the statute is contrary to the purpose and the intent of the law.

Therefore, we require that when additional generating units are added to a deemed-compliant CCGT baseload powerplant resulting in an increase of 50 MW or more to the powerplant's rated capacity, those additional units must demonstrate compliance with the EPS. We select a 50 MW threshold because it is already used to mark the boundary between significant and minor changes in generating capacity for the purpose of triggering CEC powerplant permitting requirements under Public Resources Code § 25123.[84] In this way, we avoid the

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[82] *Landrum* v. *Superior Ct. of LA County*, (1981) 30 Cal.3d 1, 9.

[83] Under the definition of "powerplant" discussed in Section 4.2.4 above, adding a new CCGT baseload generating unit to the site that is not operationally dependent on one or more of the existing generating units within the deemed-compliant powerplant is equivalent to adding a new, separate baseload powerplant. Under these circumstances, the new unit would be subject to the same triggers for EPS compliance (irrespective of MW size) as any other baseload powerplant.

[84] By citing Public Resources Code § 25123 in this case we are not adopting the language of the statute generally, nor are we importing any of the case law, regulations, or CEC decisions that have been generated in the process of interpreting that section, or the 50 MW number specifically.

absurd result of creating a loophole that would allow for the installation of an unlimited amount of new capacity at an existing CCGT powerplant without any demonstration that that new capacity complies with the EPS. On the other hand, by not requiring deemed-compliant CCGT powerplants to demonstrate compliance with the EPS for repowering as it is defined within the context of "new ownership investments," we eliminate the redundancy that would otherwise exist between §§ 8340(j), 8341, and 8341(d)(1) with respect to retained generation.[85] While the addition of new units resulting in an increase of 50 MW or more to a powerplant's rated capacity is certainly a "new ownership investment," as we define it above, it is a subset of all the possible activities that would constitute "new ownership investment." Thus, by limiting our reading of what parts of a CCGT powerplant are deemed compliant (to exclude additional units totaling 50 MW or more) we avoid redundancy and give each word of § 8341(d)(1) a legal effect distinct from the other provisions of the statute.

Furthermore, nothing in today's decision or in SB 1368 limits the Commission's existing authority to require that utility-owned, or contracted for, CCGT powerplants are properly maintained and are operated as cleanly and efficiently as possible. The Commission retains the right to address questions related to the maintenance and efficiency of CCGT powerplants including but not limited to, the emissions from these plants, in the investor-owned utility

[85] In particular, under §§ 8340(j) and 8341, compliance with the EPS is triggered for LSE retained baseload generation only when there is a "new ownership investment" in those facilities. If we construed § 8341(d)(1) to mean that the very same "new ownership investment" trigger that applies to LSE retained generation applies equally to LSE-owned "deemed-compliant" retained CCGT generation, there would be redundancy among these sections of the statute.

general rate cases, long-term procurement plans, or other appropriate proceedings.

Putting this within the context of the other provisions of SB 1368 and our discussion of covered procurements, this means that an LSE-owned CCGT baseload powerplant deemed compliant under § 8341(d)(1) must demonstrate compliance for any units that it adds to its CCGT powerplant that result in an increase of 50 MW or more to the powerplant's capacity as it was rated on the day it was deemed compliant. In effect, we will treat the additional unit(s) that result in an increase of 50 MW or more to the powerplant capacity as a separate powerplant for the purpose of demonstrating EPS compliance. The following example shows how we will prevent CCGTs from circumventing EPS compliance by piece-mealing additions of capacity: a deemed-compliant CCGT powerplant which adds 25 MW of capacity in 2008 and another 25 MW in 2010 will have to show actual EPS compliance for the additional capacity in 2010. The rated capacity of CCGTs for the purpose of establishing when the 50 MW addition is reached will be: 1) for all CCGT powerplants that are in operation on the effective date of this decision—the rated capacity of the powerplant that is operating, or 2) for all other CCGT powerplants (or additions to powerplants) that obtain a CEC final permit to operate as of June 30, 2007—the rated capacity authorized by the permit.

A LSE is also required to demonstrate compliance with the EPS for any new or renewal contract of five years or longer with any CCGT baseload powerplant deemed compliant under § 8341(d)(1) that added new units resulting in an increase of 50 MW or more to the powerplant's rated capacity, as defined above. However, the LSE need only demonstrate EPS compliance for those CCGT units that were added to the deemed-compliant powerplant after it was

deemed compliant. Procurement contracts that exist at the time additional units are installed to a deemed-compliant CCGT powerplant (resulting in an increase of 50 MW or more) will not be required to demonstrate compliance until contract renewal.

In sum, consistent with the provisions of SB 1368, our adopted interim EPS will apply to:

(1) New ownership investments in baseload generation made by an LSE, defined as:
   (a) Investments in new baseload powerplant (new construction), or
   (b) Acquisition of new or additional ownership interest in existing baseload powerplant previously owned by others, or
   (c) New investments[86] in the LSE's own existing, non-CCGT baseload powerplants that:
      (i) are designed and intended to extend the life of one or more units by five years or more,
      (ii) result in a net increase in the rated capacity of the powerplant, or
      (iii) are designed and intended to convert a non-baseload plant to a baseload plant, or
   (d) Units added[87] to a deemed-compliant CCGT powerplant that result in an increase of 50 MW or more to the powerplant's rated capacity,[88] or

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[86] Only those units in a multi-unit powerplant that are being added, replaced or altered must comply with the EPS. In any event, additional units may be considered "new" powerplants as discussed in Section 4.2.4, in which case they would be covered procurements under (1)(a) above.

[87] Only the additional units must demonstrate compliance with the EPS. "Additional" units refer to units that were not previously operating at that specific powerplant

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(2) New contract commitments (including renewal contracts) of five years or greater by an LSE with:

(a) baseload generation facilities, unless those facilities represent deemed-compliant CCGT powerplants, or

(b) any deemed-compliant CCGT powerplant that added units resulting in an increase of 50 MW or more to the powerplant's rated capacity. (The contracting LSE need only show that the added units meet the EPS).

In addition, we note that the statute does not specify how to establish the "term" of a contract. In order to implement this program effectively, we must clearly explain how to determine the "term" of a contract. Accordingly, for EPS-purposes we will define the "term" of a contract as "the date of first delivery through the date of last delivery (even if there are intervening periods during which there are no deliveries)." Thus, for example, a contract that provides for summer-only deliveries beginning in 2007 and ending in 2011, does *not* have a term of five years or more, because the last delivery occurs less than five years after the first delivery. On the other hand, a contract that provides for summer-only deliveries beginning in 2007 and ending in 2012 *does* have a term of more than five years, because the last delivery occurs more than five years after the first delivery. The date on which the contract is executed is *not* relevant in determining the "term" of the contract. Thus, in the above examples, it would

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(including additional refurbished or used units previously operating at a different powerplant).

[88] For the purpose of establishing when there has been a 50 MW addition, the existing rated capacity will be determined as follows: 1) for all CCGT powerplants that are in operation on the effective date of this decision—the rated capacity of the powerplant that is operating, or 2) for all other powerplants (or additions to powerplants) that obtain a CEC final permit to operate by June 30, 2007—the rated capacity authorized by the permit.

make no difference whether the contracts mentioned were executed in January of 2006, or May of 2007.

4.3. EPS Performance Level (Emissions Rate)

Section 8341(d)(1) directs the Commission to establish an EPS performance level that is "no higher" than the rate of GHG emissions of a CCGT baseload powerplant. In that same section, SB 1368 includes the grandfathering provisions discussed above; namely, that "all combined-cycle natural gas powerplants that are in operation, or that have an Energy Commission final permit decision to operate as of June 30, 2007, shall be deemed to be in compliance with the greenhouse gases emissions performance standard."

The statute does not specify the emissions rate of a CCGT that it to be used for the EPS performance level. At the direction of the assigned ALJ, parties presented data on heat rates and emission factors for different types and vintages of CCGT powerplants and other generation technologies.[89] Parties were directed to specifically consider this data in presenting their proposals for the EPS performance level.

The initial staff "straw proposal" presented during workshops recommended a dual standard—one for existing resources (at a higher emissions rate) and one for new resources (at a lower one). In its draft report, staff modified this proposal and recommended instead a single EPS emissions rate of 1,000 lbs of CO_2/MWh (or "lbs/MWh"). After further consideration of the data, parties' comments and the provisions of SB 1368, staff now recommends that a

[89] Responses to the ALJ's request are posted at the Commission's website at www.cpuc.ca.gov/static/energy/electric/climate+change.

single EPS emissions rate be established at 1,100 lbs/MWh. As discussed above, staff also recommends in the final report that existing CCGT's "deemed compliant" under § 8341(d)(1) be required to demonstrate compliance when repowered or upon contract renewal.

Independent Energy Producers Association (IEP), GPI, PG&E, SCE, SDG&E/SoCalGas (filing jointly), Energy Producers and Users Coalition and Cogeneration Association of California (EPUC/CAC, filing jointly) among others support an EPS level of at least 1,100 lbs/ MWh for a variety of reasons, including:

- An EPS level of 1,100-1,200 lbs/MWh would accommodate different CCGT configurations, some of which may have higher heat rates in order to meet other (non-greenhouse gas) environmental objectives, such as a facility with dry cooling technology for purposes of minimizing water use, or efficiency. (PG&E, IEP, GPI)
- A lower level (e.g., 1,000 lbs/MWh) would not appropriately take into account intermediate units, including reciprocating engine units that will be needed for reliable operation of the grid. (PG&E)
- An EPS level of at least 1,100 lbs/MWh would ensure satisfaction of SB 1368's mandate that all CCGTs currently in operation be deemed compliant with the EPS. (SDG&E/SoCalGas).
- An EPS even higher than 1,100 lbs/MWh should be set in order to ensure that all existing gas-fired units, not just CCGTs, are available for procurement. (EPUC/CAC, Center for Energy and Economic Development (CEED).)[90]

[90] More generally, CEED objects to the staff proposed EPS of 1,100 lbs/MWh because at that level it would preclude powerplants that use oil, coal, petroleum and coke-fueled resources. Although CEED does not propose a specific EPS level in its comments, the record indicates that the EPS would need to be on the order of 1,700-1,800 lbs/MWh in order for baseload generation using these resources to be able to meet the standard.

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Division of Ratepayer Advocates (DRA), Sempra Global (Sempra), Calpine Corporation (Calpine) and NRDC support an EPS level of no more than 1,000 lbs CO_2/MWh. They argue that there is no need, based on the data presented in this proceeding, to set the EPS level higher than 1,000 lbs CO_2/MWh, given that SB 1368 already deems all existing CCGTs to be in compliance. DRA, in particular, contends that it is unnecessary to raise the EPS to 1,100 lbs/MWh to accommodate the minor reduction in efficiency associated with dry cooling.

In considering this issue, we note that SDG&E/SoCalGas interpret § 8341 (d)(1) to mean that the Legislature intended for all deemed-compliant CCGTs to be able to demonstrate that they would pass the adopted standard. We disagree with this interpretation. As we point out in Section 4.2.4 above, the verb "deem" means "to treat something as if (1) it were really something else, or (2) it has qualities that it doesn't have."[91] This common definition, in conjunction with § 8341(d)(1)'s requirement that the Commission adopt an EPS that is no higher than the rate of emissions for CCGT baseload generation, indicates that the Legislature intended to allow the Commission to adopt a standard that some CCGT powerplants might not be capable of meeting. While many deemed-compliant CCGT powerplants will certainly also be capable of demonstrating "actual" compliance, some fraction of deemed-compliant CCGTs may not be capable of demonstrating compliance with the EPS if they were required to do so. Nonetheless, under the provisions of § 8341(d)(1), they will be treated as if

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However, CEED ignores that fact that selecting this higher EPS level would not produce the amount of GHG emissions reduction that the statute clearly intends, as evidenced by the selection of a CCGT-based standard.

[91] Black's Law Dictionary, 7th Ed, at 424, West Publishing (St. Paul, Minnesota © 1999).

they had passed the standard. Therefore, we do not agree with SDG&E/SoCalGas' recommendation that we should establish the EPS level high enough so that it could be met by all deemed-compliant CCGTS, if they were required to comply.

Nor do we agree with EPUC/CAC's suggestion that we establish the EPS level high enough to ensure that all gas-fired units would meet it. Had the Legislature intended for the EPS to reflect the GHG emissions rate associated with gas-fired units, not just CCGTs, it would have stated so explicitly. Instead, the Legislature selected combined-cycle, gas-fired power generation as the basis for the EPS. We must assume that in doing so, the Legislature recognized that CCGT technology is considered to be the "technology of choice" for new, baseload power generation fired by natural gas because of its efficiency advantages over other forms of gas-fired power generation.[92] Moreover, the Legislature specifically directed that the emissions rate be reflective of a "baseload" CCGT powerplant, and not intermediate/load shaping gas-fired units, as some parties suggest in their comments.

That leaves us with the selection of a specific level of lbs of CO_2/MWh emissions that is "no higher than the rate of emissions of greenhouse gases for combined-cycle natural gas baseload generation." The record in this proceeding establishes the following:[93]

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[92] See, *Comments of the Green Power Institute on the Final Workshop Report,* October 18, 2006, Appendix A, pp. 18-19.

[93] Except as otherwise noted, the data summarized below is from the responses to the ALJ's request that are posted at www.cpuc.ca.gov/static/energy/electric/climate+change under Request #3.

- Based on the million British thermal units (MMBtus) consumed by CCGTs in California in 2004 and 2005 as reported in the CEC's Continuous Emissions Monitoring System (CEMS), CCGTs with capacity factors of 60% or more had emissions as low as 833 in 2004 and 794 in 2005.
- Based on the same CEMS reported data, CCGTs with capacity factors of 60% or greater had emissions as high as 1058 in 2004 and 1006 in 2005.
- The weighted average of emission rates based on the 2004/2005 CEMS data for baseload CCGTs is in the range of 856-915 lbs of CO_2/MWh, depending on whether energy or capacity is used as the weighting factor.
- Data from the CEC dating back to 2000 for CCGTs in the Western Energy Coordinating Council region show some facilities not included in the foregoing data with capacity factors greater than 60% and with emission rates ranging from 993-1208 lbs of $C0_2$/MWh.[94]
- Dry cooling, which offers the benefit of lower water consumption, increases the heat rate of a CCGT on the order of 1.5%. [95]

Based on this information, the Proposed Decision concluded that establishing an EPS standard for CO_2 emissions of 1,000 lbs/MWh was reasonable. However, after considering the comments on the Proposed Decision, we are persuaded that allowing a small amount of leeway above this threshold would more appropriately take into account smaller-sized CCGTs utilizing

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[94] *Comments of PG&E on Draft Workshop Report*, September 8, 2006, p. 12.

[95] *Opening Comments and Legal Arguments of DRA on the Final Workshop Report on Phase 1 Issues*, October 18, 2006, p. 11, referencing Resolution E-3940, where the Commission found that a 1.5% increase in the referent CCGT baseload powerplant heat rate was an appropriate value to use to reflect the impact of dry cooling.

newer technologies, as well as the variability in heat rates based on altitude and ambient temperatures where the facility is located.[96]

We conclude from the data and considerations described above, that establishing an EPS standard for CO_2 emissions of 1,100 lbs /MWh is reasonable. It represents a level that reflects emission rates associated with both existing and new baseload CCGT units and reasonably accounts for potential CCGT plant "outliers" from the average CEMS that utilize dry cooling technologies, are smaller-sized facilities or are located in the desert or at high altitudes. At the same time, it avoids establishing a standard that is representative of the most inefficient, older deemed-compliant CCGT powerplants currently in operation. In this way, our adopted level reflects the intent of the Legislature to base the EPS on CCGT emissions rates, while acknowledging the concern reflected in the statute's grandfathering provisions that some of the older, less efficient CCGT powerplants currently operating may not be able to meet it.

In sum, we find that an EPS level of 1,100 lbs of CO_2/MWh to be reasonable, and we shall adopt it.

4.4. Application of EPS to Contracts: Deliveries or Underlying Facility?

One of the threshold design issues in Phase 1 is how the EPS should be applied to contracts. While all parties agree that the characteristics of the facility supplying the energy should be considered when applying the EPS to new

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[96] See, in particular, *Comments of the Northern California Power Agency on the December 13 2006 Draft Interim Opinion*, January 2, 2007, pp. 4-8. All other things being equal, CCGT powerplants located in a desert (high ambient temperature) or high altitude areas will have higher heat rates (and higher GHG emissions) than those located in the coastal regions of California.

ownership investments, there was considerable debate during Phase 1 on whether the same should apply when considering contract commitments. The discussion focused on the treatment of "specified contracts" since, by definition, these are contracts where the generating units or facilities providing the power are known. We address the treatment of "unspecified" contracts in a separate section of this decision. (See Section 4.12.)

Some parties (including TURN, NRDC, UCS and WRA) recommend that this determination be made based on the annualized operations of the underlying facility or facilities, regardless of the type of contract deliveries. Staff supports this approach. Other parties (EPUC, CAC, SDG&E and SoCalGas) recommend that the Commission assess the capacity factor based only on the energy made available under the contract to the LSE, rather than on the operations of the underlying powerplant. These parties contend that this approach is supported by the "supplied under" language of in §§ 8341(a),(b)(1) and (3), in which the Legislature directs that baseload generation "supplied under" a contract or long-term financial commitment shall comply with the EPS.

In our view, accomplishing the goals of SB 1368 and this Commission's GHG reduction policies requires us to look at the characteristics and emissions of the powerplant(s) being contracted for, *not* just the characteristics of the contracted-for deliveries, as some parties propose. Indeed, it is the characteristics of the powerplant(s) underlying those financial commitments that create the potential financial risk to California consumers and exposure to future reliability problems that this Commission and the Legislature seek to reduce through the establishment of an EPS, as both have clearly expressed. (See Section 3 above.)

Moreover, the rules of statutory construction support a facility-based application of the EPS. As the Courts have stated on numerous occasions: "It is a cardinal rule of statutory construction that in attempting to ascertain the legislative intention effect should be given, whenever possible, to the statute as a whole and to every word and clause thereof, leaving no part of the provision useless or deprived of meaning."[97] Focusing on the phrase "supplied under" to conclude that the Legislature intended for EPS compliance to apply only to contracted-for power deliveries violates this rule. In particular, it would render useless the language of § 8341(4) that states:

> "In determining whether a long-term financial commitment is for baseload generation, the commission ***shall consider the design of the powerplant and the intended use of the powerplant*** as determined by the commission based upon the electricity purchase contract, any certification received from the Energy Commission, any other permit or certificate necessary for the operation of the powerplant, including a certificate of public convenience and necessity, any procurement approval decision for the load-serving entity, and any other matter the commission determines is relevant under the circumstances."[98]

In opening comments on the Proposed Decision, the California Municipal Utilities Association (CMUA) and EPUC/CAC quote selected phrases from this section to support their positions concerning what the Commission should consider in determining if the financial commitment is subject to the EPS. In particular, CMUA refers to phrases "the electricity purchase contract" and "any procurement approval decision for the load serving entity" in this section to

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[97] *Gay Law Students Association* v. *Pac. Tel. & Tel. Co.*, (1979) 24 Cal.3d 458, 478, citing *Weber* v. *County of Santa Barbara* (1940) 15 Cal.2d 82, 86.

[98] § 8341 (b) (4), emphasis added.

support its position that application of the EPS should consider the characteristics of the LSE's commitment (and not just the capacity factor of the underlying facility) when that facility is owned and operated by a customer generator or represents bottoming cycle cogeneration.[99] In its opening comments, EPUC/CAC highlights the phrases "based upon the electricity contract" and "any other matter the commission determines is relevant under the circumstances" to support its argument that, in the case of assessing the baseload characteristics of a third-party contract, it is the contract deliveries (not the underlying facility) that determines the financial commitment of the LSE and defines the commitment subject to regulation.[100] Both CMUA and EPUC/CAC improperly construe these selected portions of § 8341 (b)(4) by taking them out of context. When considered in the full context of this section, the phrases "the electricity purchase contract," "any other permit or certificate," "any procurement approval decision for the load-serving entity" and "any other matter the Commission determines is relevant" refer to the type of information the Legislature expects the Commission to evaluate as it considers the "design of the powerplant and the intended use of the powerplant" for the purpose of "determining whether the long-term financial commitment is for baseload generation." It makes sense for the Legislature to have included the electricity purchase contract in this listing, since information contained in those contracts—such as the specific facilities providing the output—would be relevant to the

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[99] *Comments of CMUA on the Proposed Decision,* January 2, 2007, pp. 11-12, 14.

[100] *Comments on the Proposed Decision of EPUC/CAC,* January 2, 2007, p. 5.

Commission's consideration of the design and intended use of the powerplant. However, contrary to CMUC and EPUC/CAC's assertions, it does not follow that this section permits the Commission to consider alternative or additional criteria other than "the design of the powerplant and the intended use of the powerplant" in determining whether the commitment is for baseload generation.

We also note that in all instances where it appears in the statute, the phrase "supplied under" follows the term "baseload generation" which is defined by § 8340(a) in terms of *electricity generation from a powerplant* that is designed and intended to provide electricity at an annualized plant capacity factor of at least 60%. The term "plant capacity factor" is also defined by § 8340(l) in reference to the underlying plant operations, i.e., as *the electricity the unit could have produced it had it been operated at its rated capacity.* We interpret SB 1368 to ensure that LSEs do not enter into contracts with powerplants designed and intended for baseload operations with GHG emissions higher than combined cycle natural gas powerplants. Had the Legislature intended to only consider the terms of the contract (or deliveries under that contract) rather than the underlying facility in determining whether a contract supplied "baseload generation," it would have defined that term as well as "plant capacity factor" to clearly reflect that intent.[101]

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[101] The legislative history of SB 1368 supports the plain meaning of the statute. During the Senate Third Reading of SB 1368, the committee report states that "the purpose of this bill is to prevent long-term investments *in powerplants* with GHG emissions in excess of those produced by a combined-cycle natural gas power plant." The report also states that the bill would apply to contracts for "baseload power," where baseload power is defined as "electricity generation *from a powerplant* that is designed to provide

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We conclude that the determination whether the EPS applies to a resource should be made based on the characteristics of the generating facilities underlying the contract, and not on the contracted-for deliveries. As staff notes in its final report, for specified contracts the capacity factor, average heat rate and emissions factor of the underlying facility or facilities supplying power should be readily available, since operators are required to provide this information to multiple regulatory agencies such as the Environmental Protection Agency and California Air Districts. Pursuant to § 8341(4), we will use reported information, information from permits and certificates, as well as any other information we deem to be relevant in order to establish the design and intended use of the generating facilities underlying the contract.

As discussed in Section 4.2.4 above, there could be instances where different resources or technologies might be generating power at the same location. For example, a generating unit utilizing a renewable resource (e.g., wind) might be located in the same site as a fossil-fueled unit. Our definition of "powerplant" in Section 4.2.4 clarifies that generating units utilizing different resources or technologies, no matter if they are at the same location, must each be evaluated as a separate powerplant for the purpose of determining whether the resource operates as baseload generation and, if so, whether its emissions rate complies with the EPS.

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electricity at least 60% of the total hours in a year (a 60% capacity factor)." See, for example, Senate Third Reading of SB 1368, as amended August 21, 2006, pp. E, F.

4.5. LSE Contracts with Customer Generators

A related issue is how to treat LSE contracts with powerplants that also generate power for on-site load (referred to interchangeably in comments as "customer generators," "self-generators" or "self-generation facilities"). EPUC/CAC present the example of a customer generator that has a capacity of 50 MW and uses 45 MW to serve the industrial loads of its own site, selling any surplus energy to the utility on an as-available basis. If the unit were assessed, it would appear to be operating at a very high-capacity factor. However, if the deliveries to the grid under the utility contract were assessed, those deliveries would be at a very "low-capacity factor."[102] EPUC/CAC take the position that only the electrical generation output actually delivered to the grid should be considered in determining whether the EPS will apply. In their view, it would be unreasonable to consider a 5 MW as-available sale by a customer generation facility a "baseload" powerplant in the utility portfolio.

NRDC, TURN, UCS and WRA disagree. They argue that self-generation facilities should be evaluated against the EPS based on the operational characteristics of the underlying facility, consistent with the application of the EPS to all specified contracts. Even if the amount of energy delivered to the grid is small, they contend that the facility is still a resource upon which the LSE relies, and long-term reliability risks would still be a concern if the facility is carbon-intensive. In their view, the Commission should avoid situations where

[102] The "capacity factor" in this instance would be calculated as the amount of contracted-for deliveries divided by the annual average output of the facility.

the LSE makes separate arrangements for on-site high-polluting resources, since the same risks apply to those facilities.

We agree that the EPS should be applied consistently to the characteristics of the underlying facility or facilities supplying power under contract to the LSE, irrespective of whether those facilities are operated by a customer generator or by a merchant generator (i.e., that does not use any of the power produced on site). Under either circumstances, the operating characteristics of the powerplant(s) underlying contracts of five years or more with an electrical corporation, electric service provider or community choice aggregator, as those entities are defined under the statute, should be considered in assessing whether the EPS applies. As discussed in Section 4.2.4, a powerplant is generally defined as a single generating unit for the purposes of applying the EPS rules, except when the three-prong test for a "multi-unit" powerplant described in that section is met.

We find no merit to EPUC/CAC's argument that this approach creates "a possible discrimination" between customer-owned generation and merchant generation. In fact, the example EPUC/CAC present to support this argument focuses on powerplants with no operational similarities at all except for the amount of power contracted for with the LSE.[103] The purpose of the EPS is not, as EPUC/CAC contend, to ensure that generators with similar deliveries to the grid are treated comparably. Rather, as discussed above, the purpose of the EPS

[103] See the EPUC/CAC example: A merchant generator with a combustion turbine with 5 MW capacity that has a capacity factor of 20% and an industrial customer generator with 30 MW capacity that operates at a 90% capacity factor and has a contract with an LSE to supply no more than 5 MW. *Reply Comments of EPUC/CAC on the Final Workshop Report,* October 27, 2006, pp. 8-9.

is to ensure that LSEs do not enter into long-term financial commitments with powerplants designed and intended for baseload operations that emit GHG at a rate higher than a CCGT powerplant. Under EPUC/CAC's example, it is therefore consistent with this purpose that the 30 MW generator operating at a 90% capacity factor is subject to the EPS, whereas the 5 MW generator operating at a 20% capacity factor is not (assuming that the output of both facilities is under contract with an LSE for a term of five years or greater).

Moreover, we find no merit to EPUC/CAC's contention that applying the EPS to the underlying facility in the case of customer generators represents an attempt by this Commission to exceed its jurisdiction, and is "not allowed by law."[104] In particular, EPUC/CAC argue that § 218 "excludes cogenerators from the jurisdiction of the Commission to the extent their generation is delivered on-site or over the fence," and therefore concludes that the Commission's jurisdiction is limited by law to the contract deliveries to the LSE.[105]

By law, the EPS governs the long term financial commitments of LSEs to *any* baseload generation, and SB 1368 directs this Commission to design and implement an EPS for this purpose.[106] Therefore, once a customer generator decides to offer power over and above its own (or over the fence) on-site consumption to an LSE under a contract with a term of five years or more, the power supplied under that contract comes under our purview for the purposes of evaluating the LSE's (not the customer generator's) compliance with the EPS. For the reasons discussed above, we have determined that the criteria for

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[104] *Ibid.*, p. 10.

[105] *Id.*

[106] §§ 8341(a) and (b).

determining whether or not the long-term financial commitment of the LSE meets the EPS (annualized capacity factor and emissions rate) should, and statutorily must, apply to the underlying facility.

4.6. Treatment of Partial Contracts

The issue of how to treat partial contracts is also related to the question of whether the contract terms or the underlying facility should be considered when applying the EPS. The example discussed at the workshop was a summer product contract for power from a specified pulverized coal plant. Staff recommends that the expected capacity factor of the contractual commitment (not the underlying powerplant(s)) be considered for any partial-year contract. Therefore, if the commitment under the contract represented less than a 60% capacity factor on an average annual basis, it would not be subject to the EPS.[107] In staff's view this is reasonable because such contracts would likely be addressing seasonal reliability issues. PG&E concurs with this approach for similar reasons.[108]

NRDC, GPI, IEP and others object to this treatment of partial contracts, arguing that a blanket exemption for seasonal procurements is both unnecessary and inconsistent with the intent and purpose of the EPS. In particular, they argue that if the purpose of a partial year contract is to address system reliability concerns, then the contract would probably be less than five years in duration and therefore not subject to the EPS. In any case, they point out that such

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[107] Under this treatment, the "capacity factor" would also be calculated by dividing the amount of contracted-for energy deliveries by the annual average output of the facility.

[108] *Comments of PG&E on Draft Workshop Report,* September 8, 2006, p. 9.

concerns can be addressed by providing for case-by-case review of reliability exemptions, rather than creating a loophole for partial contracts.

We agree. Considering the expected capacity factor of the partial year contractual commitment (rather than of the underlying powerplant) is clearly inconsistent with other aspects of the EPS we adopt today. Such treatment could easily permit baseload generation that would otherwise be prohibited from supplying power to the LSE to supply that power by simply limiting the time period for deliveries. The example presented by IEP clearly illustrates this inconsistency:

> "For example, an out-of-state coal plant might enter into a long-term contract to provide baseload power to a California [LSE] for the months of May through October. This unit could also sell its output to another buyer (either an out-of-state buyer or a different California LSE) for the months of November through April. Even if the unit underlying this contract were to run at or near a 100% capacity factor level (certainly not a "shaping" resource by any stretch of the imagination), staff's recommended annual average basis for evaluation would show this resource to have less than a 60% capacity factor and thus not be subject to the screen."[109]

We agree with NRDC, TURN, UCS, GPI, IEP and others that there is no compelling reason to make a distinction for partial procurements based on horizontal or vertical slices of a facility's output. We already incorporate design parameters into the EPS that will minimize the potential impact of the standard on reliability concerns, and as we discuss in Section 4.8.5, provide for a case-by-case exemption to the EPS based on reliability considerations. This enables us to

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[109] *Comments of the Independent Energy Producers Association on the Draft Staff Workshop Report*, September 8, 2006, pp. 2-3.

carefully assess those circumstances where waiver of the adopted EPS may be necessary to address reliability issues through a long-term seasonal contract, without creating an unnecessary loophole in our application of the EPS.

Instead, we will apply the same principle to partial contracts that we apply to other specified contracts, namely, that the generating facility underlying the contract (and not the contracted-for deliveries) will determine whether the commitment is for baseload generation and, if so, the associated emissions rate.

4.7. Treatment of Multiple Generating Sources, Including Contracts with Renewables Firmed by Non-Renewable Resources

Under the staff proposal, each individual generating source underlying a contract where those sources are specified must meet the EPS, with the exception of "firmed renewable products." Under these types of contracted-for deliveries, a renewable resource provides as-available energy and a non-renewable source or sources provide additional "firming" energy, so that the total amount of energy sums to an agreed upon amount. For firmed renewable products, staff proposes that the blend of the emissions from the renewable and non-renewable resources must meet the EPS. In the case of a renewable resource firmed by an unspecified resource, staff would similarly blend the imputed emissions value for that unspecified unit with those of the renewable resource. (See Section 4.12 below on how staff proposes to impute emissions rates for unspecified sources.)

In general practice, staff's proposal for firmed renewable products means the following: As long as the proposed procurement of firmed renewable energy is for deliveries with an annual average capacity factor below the 60% threshold level, then the procurement is automatically exempt from the interim EPS. If the procurement has an annual average capacity factor above this threshold, it

generally means that half of the energy deliveries or more under the procurement will be from the non-renewable firming resource, and the procurement would be subject to the interim EPS. Under these circumstances the procurement would be judged as a whole (emissions of renewable and firming energy combined on an annual average basis), rather than applied to each generator separately.

There is general concurrence among parties with staff's overall recommendation on the treatment of contracts with multiple generating sources, namely that each source be treated individually for the purpose of determining both the capacity factor and net emissions rate.[110] However, there is considerable debate over staff's blending proposal with respect to firmed renewable products. We discuss the range of views below.

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[110] EPUC/CAC requests that the Commission specifically clarify that the treatment of multi-unit contracts would be applied on a unit basis where two or more units in a generating station are used for different purposes, as illustrated in the following example:

> "A multi-unit facility may enter into one contract with an LSE. The contract could provide for 50 MW of energy at an 80% capacity factor from Unit 1, and a 20 MW peaking product, not to exceed a 30% capacity factor, from Unit II. The contract for the production from Unit 1 would pass the screens, and the EPS would be applied to Unit 1. However, the product from Unit II would not pass the screens for either minimum size or baseload capacity factor." (*Comments of EPUC/CAC on Final Workshop Report*, October 18, 2006, pp. 11-12.)

However, this example (and EPUC/CAC's request for clarification) is only relevant in the context of an EPS that looks at contract deliveries or products, rather than the operations of the underlying powerplant (as that term is defined in SB 1368). As discussed throughout today's decision, this is not the context for our adopted EPS (nor is consideration of a size threshold), and therefore the clarification that EPUC/CAC seeks here is neither relevant nor appropriate.

PG&E does not support staff's position on this issue. Instead, PG&E recommends that any resource eligible under the RPS program should be categorically deemed in compliance with the EPS, without regard to the characteristics of any firming non-renewable resource behind the RPS-eligible resource.[111] LL Power supports this approach.

GPI opposes PG&E's proposal for a blanket exemption to the EPS for firmed renewable products, arguing that this could provide a significant loophole for bringing high GHG-emitting baseload resources to California LSEs. Like staff, GPI examines the issue of how to treat a renewable product firmed by a non-renewable resource from the viewpoint of contract deliveries. GPI gives the example of a firmed wind contract for 8,760 hours of scheduled energy deliveries at the wind generator's rated capacity, where some two-thirds or more of the delivered energy under the contract would be firming power, rather than renewable. In this instance, GPI argues that a blanket exemption could permit contract deliveries of a baseload product that does not meet the EPS on even a blended basis. Instead, GPI supports the staff proposal to apply the EPS on a blended basis to firm renewable products, rather than apply the EPS separately to each source of power. GPI argues that this is appropriate because the relative contributions of the two sources of power under the procurement (renewable and firming) are intrinsically linked.

In contrast, NRDC, TURN, UCS, WRA and DRA argue that staff's proposed treatment of these contracts (and by extension, GPI's) runs counter to

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[111] Resources that count towards the utilities' RPS requirements are established by the CEC and set forth in The RPS Eligibility Guidebook at: http://www.energy.ca.gov/2006publications/CEC-300-2006-007/CEC-300-2006-007-F.PDF.

the intent of SB 1368 that the standard is to be applied to the underlying facilities behind a contract, not a blend of their emissions. These parties are particularly concerned that this exception would allow high-emitting resources that would never pass the standard alone (such as pulverized coal) to be blended with zero-emitting renewable resources. In their view the interim EPS should be applied in a manner consistent with the plain language of the statute, even for firmed renewable products.

Plumas-Sierra Rural Electric Cooperative (Plumas-Sierra) does not comment on the specific proposals described above, but generally urges that "that Commission implementation of the standard not result in a perverse situation where an entity delivering a totally clean and renewable resource is penalized by having a firming facility deemed a 'baseload resource.'"[112]

In our view, the position advocated by NRDC, TURN, UCS, WRA and DRA is most consistent with the plain language of SB 1368. As we discussed in Section 4.4 above, SB 1368 requires that EPS compliance be based on the underlying powerplant or powerplants producing power, not just the delivered product under a contract. As NRDC and others point out, allowing a blanket exception for firmed renewable products would permit high-emitting baseload powerplants that would never pass the standard alone to be blended without restriction with zero-emitting renewable powerplants, thereby circumventing the intent of the interim EPS. Accordingly, for contracts with multiple generating

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[112] *Comments of the Plumas-Sierra Rural Electric Cooperative...on the October 2, 2006 Workshop Report and Staff Proposal for an Interim Emissions Standard*, October 18, 2006, p. 4.

sources, each specified powerplant must be treated individually for the purpose of determining both the annualized capacity factor and net emissions.

At the same time, SB 1368 recognizes the importance of renewable resources for the achievement of the state's energy policies,[113] and today's decision should avoid creating impediments to long-term contracting with these resources in the process of meeting the requirements and goals of the statute. As discussed in Section 4.12 below, we believe that proposals put forth by PG&E and SMUD for the limited use of substitute system power in long-term contracts suggest a way we can provide a reasonable level of contracting flexibility for firming deliveries with renewables that does not undermine the objectives of the statute.

In sum, for contracts with multiple, specified generating sources, each specified source (powerplant) must be treated individually for the purpose of determining both the annualized capacity factor and net emissions. Based on the definition of "powerplant" presented in Section 4.2.4, this generally means that each generating unit supplying power under the contract will be evaluated individually for EPS compliance. Our EPS rules for long-term contracts (five years or more) with unspecified sources, including the use of substitute system energy to firm deliveries from renewable resources, are addressed in Section 4.12.

4.8. Proposed Exemptions from the EPS Standard

Staff recommends four areas of exemptions from the EPS standard. The first is a categorical exemption for any covered procurement that represents a

[113] See SB 1368, Section 1 (c) and (d).

commitment of less than 25 MW. This size threshold would be based on the unit size for new ownership investments, and on the amount of power contracted for under either specified or unspecified contracts.

Staff also recommends three areas where the Commission could provide exemptions from the EPS on a case-by-case basis, at its discretion. The first is a research, development and demonstration (RD&D) exemption for higher-emitting facilities upon demonstration that the commitment in question would make a significant contribution to developing a lower-emitting resource mix in the future. In addition, staff recommends that the Commission allow for reliability and cost-based exemptions on a case-by-case basis, at the discretion of the Commission.

We discuss each of these proposed exemptions, as well as additional ones recommended by parties in their comments, in light of SB 1368.

4.8.1. Small Size Exemption

As discussed in the draft and final reports, staff concludes that a 25 MW size threshold is reasonable because, among other things, it is compatible with the Air Districts and federal environmental regulations and would comport with the Northeastern Regional Greenhouse Gas Initiative emissions cap program. Prior to the passage of SB 1368, most parties supported the staff proposal to exclude specified resources under 25 MW from the EPS for these and other reasons. In addition, many parties supported staff's recommendation to apply the same size threshold to all contracts, including unspecified, in order to maintain consistency and to minimize administrative complexity.

Since the passage of SB 1368, however, IEP, DRA, GPI and SCE conclude that a size exemption is not permissible under the new law, and now recommend against any size exemption for that and other reasons. While NRDC, TURN,

UCS and WRA acknowledge that the language of the statute supports the argument for not having a size threshold at all, these parties still support a *de minimus* size threshold of 5 MW, consistent with the maximum size limit under the Self-Generation Incentive Program. They also recommend that the size threshold apply to the underlying facility, not the contract or amount delivered to the grid. These parties oppose any size exemption for unspecified contracts, since it is impossible to identify the resources behind these contracts

PG&E, on the other hand, argues that the staff proposal for a 25 MW size threshold for both specified and unspecified contracts is consistent under SB 1368, and continues to support this proposal.[114]

In our view, a size exemption of any size is incompatible with SB 1368. Section 8341(a) directs that "no load-serving entity or local publicly owned electric utility may enter into a long-term financial commitment unless *any* baseload generation supplied under the long-term financial commitment complies with the green house gases emission performance standard established by the commission" and § 8341(d)(1) requires this Commission to "establish a greenhouse gases emission performance standard *for all* baseload generation of load-serving entities" by February 1, 2007. (Emphasis added.) Nowhere in the statute does the language suggest that "all" or "any" may be qualified by the size of generating units covered or contracted-for deliveries. In its discussion of this

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[114] PG&E basically argues that since SB 1368 authorizes the Commission to adopt rules to implement and enforce the EPS required by SB 1368, the Commission may balance the GHG reduction goals of the Legislature with other goals and conclude that there is little risk that a small size exemption will undermine the intent of SB 1368. See *Comments of PG&E on Final Staff Recommendation on Greenhouse Gas Emissions Performance Standard*, October 18, 2006, pp. 2-3.

issue, PG&E fails to mention or consider the plain meaning of § 8341(a) or 8341(d)(1), thereby violating a basic canon of statutory construction.[115] As the courts have noted on many occasions: "It is a cardinal rule of statutory construction that in attempting to ascertain the legislative intention effect should be given, whenever possible, to the statute as a whole and to every word and clause thereof, leaving no part of the provision useless or deprived of meaning."[116]

We therefore cannot reconcile PG&E's position on this issue with the plain language of SB 1368. The legislative history of SB 1368 also provides no indication that the Legislature considered including an exemption for facilities or commitments under a certain size. Moreover, even though a small size exemption has some appeal in terms of administrative simplicity (i.e., reducing the number of procurements subject to the EPS), the selection of the size threshold would be an arbitrary one, and could have the unintended consequences of driving down the size of high-emitting facilities for the sole purpose of obtaining an exemption from the EPS. In addition, a blanket exemption that eliminates what could amount to be many facilities from EPS compliance could expose ratepayers to significant future risks and costs.

In their comments on the Proposed Decision, EPUC/CAC urge the Commission to reconsider a 25 MW minimum size threshold. EPUC/CAC argue that § 8341(b)(4), which permits the Commission to consider the design, intended use, and all other relevant matter in determining whether a specific plant is for

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[115] *Id.*

[116] *Gay Law Students Association* v. *Pac. Tel. & Tel. Co.*, (1979) 24 Cal.3d 458, 478, citing *Weber* v. *County of Santa Barbara* (1940) 15 Cal.2d 82, 86.

baseload generation, grants the Commission the "discretion" and "flexibility" to excuse powerplants smaller than 25 MW from complying with the EPS. EPUC/CAC's argument stems from their confusion of the distinct concepts of "rated capacity" and "plant capacity factor". "Rated capacity" means a powerplant's maximum potential electrical output, and is measured in MWs. For our purposes here, "rated capacity" is synonymous with size. "Capacity factor," on the other hand, is defined as "the ratio of electricity produced during a given time period, measured in kilowatt hours, to the electricity the unit could have produced had it been operated at its *rated capacity* during that period," and is also measured in kilowatt hours.[117] In order to determine a plant's capacity factor, therefore, we are not only permitted but required to consider the plant's rated capacity.

This is significant because SB 1368 defines baseload generation as "electricity generation from a powerplant that is designed and intended to provide electricity at an annualized plant *capacity factor* of at least 60 percent."[118] Section 8341(b)(4), the section EPUC/CAC argue permits a small size exemption, requires the Commission to consider the design and intended use of the powerplant, as well as any other relevant factors, in determining whether a financial commitment is for baseload generation, meaning generation from a powerplant with a *capacity factor* of at least 60 percent. Once the Commission has determined that a commitment is with a powerplant with a capacity factor of at least 60 percent, however, the question is resolved and the EPS applies.

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[117] SB 1368, § 8340(l).

[118] SB 1368, § 8340(a).

SB 1368 mandates that all baseload generation, meaning all generation from powerplant with a plant capacity factor of 60 percent or more, comply with the EPS. The statute requires that we use the powerplant's rated capacity, no matter how small, to calculate the powerplant's capacity factor. To excuse a powerplant with a rated capacity of 25 MW or less and a capacity factor of greater than 60 percent from complying with the EPS, therefore, is contrary to the plain language of the statute.

In support of its request that the Commission exercise whatever discretion it is granted by SB 1368 and adopt a small size exemption, EPUC/CAC cite Government Code § 11342.2, which states:

> Whenever by the express or implied terms of any statute a state agency has authority to adopt regulations to implement, interpret, make specific or otherwise carry out the provisions of the statute, no regulation adopted is valid or effective unless consistent and not in conflict with the statute and reasonably necessary to effectuate the purpose of the statute.

As explained above, granting an exemption for a class of powerplants based on their "rated capacity" is inconsistent with the definitions of "plant capacity factor" and "baseload generation." Government Code § 11342.2 expressly prohibits interpreting a statutory provision in way that is inconsistent with or conflicts with other provisions of the chapter. We therefore to decline to adopt a small size exemption.

We also interpret SB 1368 to require that all LSEs, irrespective of service territory size, must comply with the provisions of SB 1368. In its comments on the final report, CEED suggests that SB 1368 provides for an exemption for small

utilities under § 8341(d)(9), and recommends that we permit one.[119] As discussed in Section 5.3 below, § 8341(d)(9) states that the Commission may accept proposals for alternate compliance from small (less than 75,000 retail end-use customers in California) multi-jurisdictional utilities, if certain conditions are met. However, the statute does not provide for a blanket exemption from the EPS based on service territory size. Moreover, a blanket exemption for all utilities with less than 75,000 customers would not achieve the same level of emission reductions and associated reduction in future risks and costs intended by the Legislature.

For the reasons stated above, we do not adopt an exemption to EPS compliance based on the size of the facility or contractual commitment. Nor do we adopt an exemption for small utilities, except as specifically provided for under § 8341(d)(9) for multi-jurisdictional electrical corporations that meet the alternative compliance requirements of that section. (See Section 5.3 below.)

We recognize that a number of parties have been concerned specifically about the application of the EPS to small on-site generation. The Commission has several policies and a self-generation incentive program designed to encourage the installation of such small (and clean) on-site generation sources. These units appear to be the source of concern to NRDC and others. We clarify here that unless such facilities have long-term contracts (five years or greater) with LSEs for full or partial output to be delivered to the host utility grid, their output would not fall under the EPS. We do not believe that interconnection agreements with the distribution system constitute contracts for generation output as defined by the EPS rules adopted in this decision. In cases where small

[119] *CEED's Opening Comments on Final Workshop Report*, October 18, 2006, p. 6.

on-site generators do have long-term contracts to deliver output to their host utility, those agreements would fall under the EPS if the generation source is a baseload powerplant.

4.8.2. RD&D Exemption

Staff's recommendation for a case-by-case RD&D exemption is supported by a number of parties, including San Francisco Community Power, PG&E, PacifiCorp, SDG&E and SoCalGas. These parties generally argue that an RD&D exemption will assist in the introduction and adoption of new technologies that can greatly reduce GHG emissions, thereby furthering the Commission's and State's energy policies. In PacificCorp's view, the EPS will act as a deterrent to the early commercialization of IGCC technology and CO_2 sequestration projects unless we include an RD&D exemption.[120] SCE argues that, without an RD&D exemption, the EPS will drive investment towards increased reliance on natural gas, while failing to encourage investments in new technologies.[121]

Other parties, including GPI, NRDC, TURN, UCS, WRA, DRA and Calpine, oppose the staff recommendation. They argue that, although the Commission should support RD&D and deployment of advanced technologies, it must not do so at the expense of potentially undermining the EPS. In particular, they contend that because the EPS is a gateway standard, the mere assurance that an Integrated Gasification Combined Cycle (IGCC) coal plant "has or will have in a reasonable period of time the capacity and existing plan to capture and store carbon dioxide" is not sufficient to ensure that it will actually

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[120] *Post-Workshop Comments of PacifiCorp,* July 27, 2006, p. 4.

[121] *Post-Workshop Comments of SCE,* July 27, 2006.

realize such a plan and reduce and maintain emission at or below the EPS limit in the future. [122]

We believe SB 1368 provides the flexibility to both encourage new technologies while meeting the EPS. In particular, the Legislature directed us to calculate emissions rates based on "net emissions" from the production of electricity and, with respect to CO_2 sequestration projects, and provides for the following:

> "Carbon dioxide that is injected in geological formations, so as to prevent releases into the atmosphere, in compliance with applicable laws and regulations shall not be counted as emissions of the powerplant in determining compliance with the greenhouse gases emissions performance standard."[123]

Therefore, any covered procurements with a baseload facility utilizing such CO_2 sequestration projects will still need to meet the EPS (in contrast to a blanket RD&D exemption), but in calculating the net emissions rate we will not count the CO_2 that is sequestered through injection in geological formations, as directed by SB 1368.

Because of the unique nature of such CO_2 sequestration projects, we will require LSEs to file an application requesting a Commission finding of EPS compliance for any covered procurement that employs geological formation

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[122] In discussing the RD&D exemption, Staff suggests that the following type of coal generation plant could qualify: "...[A]n advanced coal facility that has an equal or better emission rate than the estimated [Integrated Gasification Combined Cycle] average heat rate and emissions, and that has or will have within a reasonable period of time the capacity and existing plan to capture and store carbon dioxide...." *Final Report*, p. 27.

[123] § 8341 (d)(5).

injection. As part of this filing, the LSE shall provide documentation demonstrating that the CO_2 capture, transportation and geological formation injection project has a reasonable and economically and technically feasible plan that will result in a permanent sequestration of CO_2 once the injection project is operational. This may mean that the sequestration project might become operational after the powerplant comes on line or the LSE enters into the contract. In implementing §§ 8341(d)(2) and (5), we clarify today that we will determine EPS compliance for such powerplants based on reasonably projected net emissions over the life of the facility.

The LSE is required to make a showing of EPS compliance by presenting projections (and documenting those projections) of net emissions over the life of the powerplant. This type of showing will ensure that the purposes of SB 1368 are served. The information presented should also include any emissions-related provisions that may be required through contract and/or permit conditions. In addition, if there are standards developed in the future by relevant regulatory or other entities, those standards should be applied in a uniform and non-discriminatory fashion for all such projects.

In sum, we conclude that a RD&D exemption for non-compliant baseload resources is inconsistent with SB 1368, but clarify how §§ 8341(d)(2) and (5) will be implemented under our interim EPS rules. We also remind parties that all RD&D projects that have an annualized plant capacity factor of less than 60% will not be subject to the EPS standard.

4.8.3. Exemption for Qualifying Facilities (QFs)

Several parties[124] argue that QFs should be exempt from the EPS because the EPS conflicts with and is thereby preempted by federal law, specifically the Public Utility Regulatory Policies Act of 1978 (PURPA).[125] In particular, parties argue that the EPS would conflict with the electric utilities' mandatory purchase obligation in 16 U.S.C § 824a-3.[126] According to these parties, applying an EPS to new contracts (or contracts up for renewal) of five or more years violates federal

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[124] Including EPUC, CAC and CCC. In its comments on the Proposed Decision , CCC contends that "if [rules adopted pursuant to PURPA] include policies favoring long-term contracts for QFs, the GHG EPS must yield to such policies." *Opening Comments of the California Cogeneration Council on the Proposed Decision*, January 2, 2006, p. 3. CCC does not cite to any rules adopted pursuant to PURPA, nor are we aware of any rules adopted pursuant to PURPA, which require policies favoring long-term contracts for QFs.

In a related argument, IEP requested consideration of an exemption for QFs based on public policy objectives of state and federal law. *Comments of the Independent Energy Producers Association on the Proposed Decision*, January 2, 2007, pp. 4-5. As discussed in this Decision, no such exemption can be justified under the requirements of SB 1368.

[125] A QF is a generating facility that meets the requirements for QF status under PURPA and part 292 of the Commission's Regulations (18 C.F.R Part 292). There are two types of QFs: (1) Cogeneration facilities that meet the requirements of 18 C.F.R §§ 292.203(b) and 292.205 for operation, efficiency and use of energy output, and (2) Small power production facilities whose primary energy source is renewable (e.g., hydro, wind solar, biomass, waste or geothermal resources) and that otherwise meets the requirements of 18 C.F.R §§ 292.203(a), 292.203(c) and 292.204. Small power production facilities are limited in size to 80 MW, with the exception of certain types of facilities certified prior to 1995.

[126] According to a recent FERC rulemaking (Docket No. RM06-10-000; Order No. 688), California electric utilities are still subject to PURPA's mandatory purchase obligation. Nonetheless, as discussed herein, SB 1368 is consistent with the provisions of PURPA, including the electric utilities' mandatory purchase obligation.

law to the extent it may disallow QFs from selling energy on a long-term basis to electric utilities.

In 1978, Congress enacted PURPA (16 U.S.C. § 824a et seq.) which amended the Federal Power Act. Congress believed encouraging the development of certain cogeneration and small power production facilities, which meet specific criteria under 16 U.S.C. § 796 (collectively called QFs), would reduce demand for traditional fossil fuels and increase the use of alternative energy sources.[127]

16 U.S.C. § 824a-3 states that the Federal Energy Regulatory Commission (FERC) shall prescribe rules that "require electric utilities to offer to ...purchase electric energy from such facilities." In accordance with 16 U.S.C. § 824a-3, FERC promulgated 18 C.F.R. § 292.303. 18 C.F.R. § 202.303 states that "Each electric utility shall purchase, in accordance with § 292.304 [Rates for purchases], any energy and capacity which is made available from a qualifying facility: (1) Directly to the electric utility; or (2) Indirectly to the electric utility. . ." Although both the statute and the regulation require electric utilities to purchase energy from QFs, neither requires the utilities to enter into long-term contracts.

Under PURPA, state regulatory bodies are required to implement FERC's rules regarding purchases and sales between QFs and electric utilities. (16 U.S.C. § 824-a3(f)).[128] States may thereby determine some of the circumstances under

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[127] *FERC* v. *Mississippi,* (1982) 456 U.S. 742, 750-51.

[128] *Accord Indep. Energy Producers Ass'n, Inc.* v. *Cal. Pub. Util. Comm'n,* (9th Cir. 1994) 36 F.3d 848, 856 (PURPA delegates to the states broad authority to implement PURPA).

which sales of electricity by QFs to electric utilities take place.[129] In its implementation of PURPA, this Commission has previously determined that PURPA does not require utilities to enter into long-term contracts to purchase QF power. As this Commission stated in D.05-09-022:

> "Neither 18 C.F.R. section 292.303 or 18 C.F.R. section 292.304(b) [FERC Rules implementing PURPA] specifies an obligation of this Commission, or any other entity, to adopt a vehicle to deliver available QF power to the utilities. Rather, . . . these CFR sections require a utility to take power made available by a QF, and to pay the cost for power that is equivalent to the utilities avoided cost of procuring or producing that power. . . . Absent from the sections . . . is any mandate that this Commission must either require long-term contracts or establish any specific delivery vehicle."

Similarly, in D.96-10-036 we stated: "We begin with Section 210 (16 U.S.C. Section 824a-3(h)), which obligates utilities to purchase electricity from QFs. . . . Taking a look at the statute, we find no mandated minimum term for PURPA required purchases. Looking to FERC regulations, we similarly find no mandated minimum term." (p. 21, *mimeo.*) In short, although federal law mandates the purchase of energy from QFs, it does not require utilities to enter into long-term contracts. Therefore, an EPS that does not prohibit a utility from purchasing energy from a QF does not conflict with federal law.

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[129] In addition, states may regulate environmental issues related to QFs. "While [PURPA] permits certain facilities to be exempt from State and Federal laws, it excludes exemptions from environmental laws. Thus a qualifying facility may not be built or operated unless it complies with all applicable local, State, and Federal zoning, air, water, and other environmental quality laws, and unless it obtains all required permits." *Small Power Production and Cogeneration Facilities - Environmental Findings*, 10 FERC ¶61,134 at 61,632 (1980). As an environmental law, SB 1368 is consistent with states' regulatory authority over QFs, as determined by FERC.

Contrary to opponents' arguments, as the language of both PURPA and the FERC regulations demonstrate, there is no provision that requires that QFs be allowed to enter into long-term contracts. After implementation of SB 1368, electric utilities will still be required to purchase energy from QFs in conformity with federal law. Utilities will simply be limited from entering into new, or renewal, long-term contracts with baseload QFs that do not meet the EPS.[130] QFs that do not comply with the EPS will still be able to enter into contracts of less than five years with the utilities. Thus we conclude that it is fully possible for electric utilities to abide by both federal law (PURPA) and SB 1368 as implemented by this Commission. Since the EPS will only apply to new contracts (or contracts up for renewal) of five or more years, electric utilities should be fully capable of complying with both federal and state law and regulation.

Furthermore, SB 1368 does not permit the Commission to exempt QFs from complying with the EPS unless there is a conflict with PURPA regulations. SB 1368 requires that:

> (a) No load-serving entity or local publicly-owned electric utility may enter into a long-term financial commitment unless any baseload generation supplied under the long-term financial commitment complies with the greenhouse gases emission performance standard established by the commission, pursuant to subdivision (d), for a load-serving entity, or by the Energy Commission, pursuant to subdivision (e), for a local publicly owned electric utility.
>
> (b)(1) The commission shall not approve a long-term financial commitment by an electric corporation unless any baseload

[130] The statute does not require any showing of compliance with the EPS for existing contracts.

> generation supplied under the long-term financial commitment complies with the greenhouse gases emission performance standard established by the commission pursuant to subdivision(d).

SB 1368 requires that "the commission shall consider and act in a manner consistent with any rules adopted pursuant to [PURPA]" when we develop and implement the EPS. (§ 8341(d)(8).) As shown above, there is no conflict between SB 1368 and PURPA. Thus, requiring QFs to comply with the EPS is consistent with the PURPA regulation and we therefore conclude that we cannot grant QFs an exemption from the EPS required by SB 1368.

If a facility uses pre-approved renewable technologies or can otherwise show compliance with the EPS, such facilities are eligible, under SB 1368, to enter into long-term contracts. Small power production facilities that use solar thermal electric, wind, geothermal or certain biomass technologies are pre-approved as compliant under this decision. Other small power production QFs, such as hydroelectric facilities, may very well be able to meet the EPS. Finally, with regard to cogeneration QFs, the cogeneration efficiencies of QFs are accounted for in calculating the emissions rates for cogenerators (see Section 4.9.), thereby assisting cogenerators in meeting the EPS. In short, there is no conflict between SB 1368 and the policy of PURPA to encourage QF generation, unless PURPA is to be read as encouraging generation from high GHG-emitting facilities.

4.8.4. Exemption for Gas-Fired Cogeneration

EPUC/CAC urge the Commission to deem all existing gas-fired cogeneration in compliance with the EPS, and thereby categorically exempt from it. In their view, this would appropriately recognize that gas-fired cogeneration

has emissions rates similar to or less than CCGTs and would avoid discrimination among forms of cogeneration.

In addition, EPUC/CAC assert that the EPS cannot reasonably be applied to bottoming-cycle cogeneration.[131] They request clarification that this technology is not included within the definition of "powerplants" under SB 1368. They argue that there are no emissions associated with the generation of electricity using a bottom-cycle generator—emissions are instead associated with the underlying industrial process. EPUC/CAC propose that the entire emissions output of such facilities should be exempt from EPS, regardless of whether the electrical output is used for on-site needs or is sold under contract to an LSE.

We do not adopt these recommendations. SB 1368 meant the EPS to apply to all cogeneration facilities since it specifies a rule for calculating the emissions of cogeneration facilities. (See § 8341(d)(3).) Had the Legislature intended to exempt gas-fired cogeneration from the EPS, it would have explicitly done so. This is clearly not the case.

We also find no basis in SB 1368 for EPUC/CAC's assertion that bottoming-cycle cogeneration is not a powerplant. SB 1368 establishes that "powerplant" means "a facility for the generation of electricity" and bottom-cycling generation uses waste heat to generate electricity. In addition, SB 1368 does not distinguish between emissions from topping-cycle and emissions from bottoming-cycle cogeneration facilities.

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[131] Bottoming-cycle cogeneration (also referred to as industrial waste-heat powered generators) is employed in industrial processes such as oil and gas producing and refining operations. Electricity is generated using a heat recovery steam generator, which generates electricity from waste heat produced by an industrial process (such as the industrial process of calcining petroleum coke).

Moreover, EPUC/CAC provide no evidence for their assertion that there are no emissions associated with the production of electricity using this technology. In fact, they acknowledge that when supplemental firing is used to enhance the performance of bottoming-cycle facilities, "any resulting emissions attributable to the supplemental firing may be considered in developing an emissions rate for the cogeneration facility."[132] Therefore, as PG&E and others suggest, the determination of net emissions from a bottoming-cycle plant should be made on a facility-specific basis.

In sum, consistent with the direction contained in SB 1368, today's adopted interim EPS will apply to cogeneration facilities. In Section 4.9 below, we address how to calculate the GHG emissions from cogeneration facilities, taking into consideration the thermal energy output contemplated by § 8341(d)(3). As discussed in that section, the calculations can be readily applied to bottoming-cycle cogeneration facilities.

4.8.5. Reliability and Cost-Based Exemptions

Turning first to reliability exemptions, we note that there is general support for staff's recommendation that the Commission should be able to, at its discretion, provide for case-by-case exemptions to the EPS based on reliability concerns. We believe that this approach is reasonable because it provides us with flexibility to address specific system reliability concerns as they may arise during implementation. It is also workable to implement, since the need to provide an exemption for reliability reasons can be readily assessed as the "go,

[132] *Comments of ECAC/CAC on the Final Workshop Report*, October 18, 2006, p. 8.

no-go" decision is being made for each new long-term financial commitments with baseload generation.

At the same time, we note that today's adopted EPS is purposely designed to both protect California ratepayers from long-term reliability risks while minimizing potential adverse impacts on short-term system reliability and associated costs. This has been accomplished by limiting the application of the EPS to long-term commitments, rather than short term transactions, and to baseload powerplants, rather than to those designed to be used for load shaping or peaking. In addition, as discussed further below, the interim EPS will be applied on a "gateway" basis, thereby providing LSEs with the flexibility to operate their facilities differently than originally designed or intended in order to address unanticipated short-term system reliability needs.[133] Therefore, we will adopt staff's recommendation for a case-by-case review of reliability exemptions only with the caveat that any consideration of such reliability exemptions comes with a heavy burden of proof on the LSE.

Any reliability exemptions must be pre-approved by the Commission and LSE requests for pre-approval shall be made by application. Pursuant to § 8341(d)(6), we will consult with the California ISO to consider the effects of such requests on system reliability and overall costs to electricity customers. Based on our analysis above, and after consulting on this matter with the California ISO, it seems unlikely that such exemption will actually be needed. However we still want to allow for the possibility of granting such an exemption in the event that unexpected reliability problems arise during implementation.

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[133] Thus, for example, an LSE might be able to temporarily operate a plant at 60% or more capacity, even though the plant was not designed or intended for such operation.

Several parties, including SCE, SDG&E and SoCalGas, support cost-based exemptions or economic safety valves on a case-by-case basis, particularly when significant economic impacts result from implementation of the EPS. These parties argue that consideration of cost impacts on a case-by-case basis is necessary to ensure that compliance costs do not escalate beyond customers' ability to pay for them. CEED argues that the "only true method to protect the ratepayer" is to establish a specific price cap for CO_2 emissions in implementing the EPS.[134]

Other parties, including GPI, NRDC and IEP strongly object to including case-by-case exemptions based on cost, or adopting other forms of economic safety valves or price caps in the EPS rule. They generally argue that the Commission's consideration of such cost-based exemptions opens the door to a parade of requests that would undermine the EPS.

In our view, approaches that would require us to assess costs or economic impacts on a case-by-case procurement basis are neither reasonable nor workable in the context of complying with the provisions of SB 1368. By its very nature and purpose, the EPS requires that each determination be made without respect to whatever other set of energy procurement opportunities a given LSE has available. This is because the EPS required by SB 1368 is designed to ensure that each baseload facility underlying a new long-term financial commitment meets a minimum level of performance, similar to an appliance efficiency standard. As GPI and others point out, in this context no single procurement can be said to cause significant cost or economic impacts, in and of itself, for a utility's

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[134] *CEED's Opening Comments on Final Workshop Report*, p. 6.

customers.[135] Moreover, while CEED criticizes the staff proposal for failing to include cost containment measures, it does not provide any evidence that the costs to ratepayers of procuring compliant resources will be high, or consider the economic, health and environmental benefits associated with EPS compliance that have been expressed by this Commission and the Legislature.[136]

CEED also faults the staff proposal for not containing price caps. However, we note that CEED does not explain how a dollar-per-ton of CO_2 price cap would apply in the context of SB 1368 performance standard requirements, i.e., to each individual "go, no-go" long-term commitment decision made by the LSE. Perhaps CEED is suggesting that a long-term commitment to an otherwise non-compliant plant should nevertheless get a "go" rather than a "no go" because the cost of reducing GHG emissions for that particular plant would exceed more than $x/ton. (Or, as in the case of the Massachusetts, Oregon and Washington price cap policies CEED mentions, the long-term commitment should be allowed because the LSE can pay $x/ton to a qualifying organization (e.g., the Massachusetts GHG Expendable Trust) for each ton above the standard.) Such an approach would allow LSEs to build, or enter into long-term contracts with high GHG emitting plants without any reduction in those plants' emissions (so long as the cost of reducing GHG emissions at those plants is high). This would clearly undermine the SB 1368 goal of protecting ratepayers from the risks of entering into long-term commitments to high GHG emitting baseload facilities in the first place. In addition, we note that CEED fails to address how

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[135] In contrast, as discussed above, a specific reliability concern and associated costs may be assessed on a procurement-by-procurement basis during EPS implementation.

[136] GHG Policy Statement; SB 1368 (Section 1).

such a price cap could realistically be established by the statutory deadline of February 1, 2007.

However, we do find merit in Sempra's suggestion that some provision be made in our rules for "extraordinary circumstances, catastrophic events, or threat of significant financial harm" that may be arise during EPS implementation due to unforeseen circumstances.[137] Therefore, we will permit an LSE to file a petition for modification of the requirements of this decision under such extreme (and therefore highly unlikely) circumstances, so long as they are unforeseen circumstances not contemplated by SB 1368 and this decision. As in the case of reliability exemptions, our consideration of such a request comes with a heavy burden of proof on the LSE. Any such request must be pre-approved by the Commission and LSE requests for pre-approval shall be made by petition for modification of this decision.

4.9. Calculation of GHG Emissions Associated with Cogeneration

SB 1368 requires the Commission to adopt a methodology for calculating the emissions rate associated with cogeneration facilities that recognizes both the thermal and electrical output associated with cogeneration.[138] The relevant provisions of SB 1368 are:

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[137] *Comments of Sempra Global on Draft Workshop Report*, September 8, 2006, pp. 7-8.

[138] Topping-cycle cogeneration plants are the most common: They produce electricity first, and then the exhaust (thermal energy) from the electricity production is used in a process application (e.g., heating). Bottoming-cycle plants produce heat for an industrial process first, and then electricity is produced using a waste heat recovery boiler. Bottoming-cycle plants are only used when the industrial process requires very high temperatures, such as furnaces for glass and metal manufacturing and calcining coke. (See Section 4.8.4 above.) These terms have also been defined by FERC regulations implementing QF policy under PURPA (18 CFR § 292.202(d) and (e).)

> 8341(d)(3) The commission shall establish an output-based methodology to ensure that the calculation of emissions of greenhouse gases for cogeneration recognizes the total usable energy output of the process, and includes all greenhouse gases emitted by the facility in the production of both electrical and thermal energy. (Emphasis added.)
>
> 8340(k) "Output-based methodology" means a greenhouse gases emission performance standard that is expressed in pounds of greenhouse gases emitted per megawatt hour and factoring in the useful thermal energy employed for purposes other than the generation of electricity. (Emphasis added.)

Below, we briefly describe the output-based methodologies addressed in comments.

4.9.1. Alternative Methodologies

Three output-based methodologies were considered by the parties: (1) the Conversion Method (proposed by CAC/EPUC), (2) the Heat Rate of the Generator Method (presented as an option in the Assigned Commissioner's Ruling), [139] and (3) the Avoided Emissions Method (proposed by SDG&E/SoCalGas). Attachment 5 presents calculations using each method to illustrate GHG emissions rates both with and without a cogeneration credit for the thermal energy output.

4.9.1.1. Conversion Method

This method accounts for the thermal energy output associated with cogeneration as follows:

TOTAL GHG EMISSIONS FROM COGENERATION FACILITY
KWH ELECTRICITY + BTU THERMAL ENERGY (expressed in kWh)

[139] *Assigned Commissioner's Ruling: Phase 1 Amended Scoping Memo and Request for Comments on Final Staff Recommendations*, October 5, 2006, Attachment 2.

Under the Conversion Method, the thermal energy measured in British thermal units (Btu) is converted into a kWh equivalent using the standard engineering conversion factor of 3.413 MMBtu per MWh, or 3413 Btu per kWh. This method is illustrated in Table A of Attachment 5 for a typical topping-cycle cogeneration facility, where 100 MMBtu of natural gas is burned (fuel in) to produce electricity. This process also produces waste heat (steam) as a by-product. The assumptions used to calculate the amount of electricity (7.8 MWh) and steam (48 MMBtu) output are described in Table D.[140] This example shows that, without accounting for any of the steam (thermal) output, the GHG emissions rate for the cogeneration facility would be 1,492 lbs/MWh. This would exceed the adopted EPS of 1,100 lbs/MWh. When the total output of the facility accounts for the steam output (producing the "cogeneration credit"), the effective GHG emissions rate drops from 1,492 lbs/MWh to 537 lbs/MWh. Thus, without the cogeneration credit the facility does not pass the EPS, whereas with the credit the facility becomes EPS-compliant.

4.9.1.2. Heat Rate of the Generator Method

The formula for this method is the same as the Conversion Method described above. However, the conversion factor used to convert the BTU THERMAL ENERGY component of the formula into kWh is the heat rate of the generator (in Btu/kWh), rather than the engineering conversion factor of 3.413 MMBtu/MWh. As a result, the denominator of the equation above is divided by a much larger number (12.750 in the Table A example). This results

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[140] Information from bottoming-cycle cogeneration facilities can be readily entered into Tables A, B and C of Attachment 5 by showing the thermal output first, followed by electric output. Table D could also be rearranged to apply to bottoming-cycle cogeneration so that thermal output precedes electric output.

in a smaller cogeneration credit and a higher resulting emissions rate. A comparison of the numerical examples in Attachment 5 shows that the Heat Rate of the Generator Method results in the highest emissions rates among the three alternative approaches, all other things being equal.

4.9.1.3. Avoided Emissions Method

The Avoided Emissions Method is different from the two methods described above in that it separately determines the emissions rate for the thermal portion of the power output. This is done by calculating the emissions associated with a proxy steam boiler (with an assumed 80% efficiency). The emissions associated with the thermal portion are then deducted from the total emissions from the cogeneration facility, and the result is then divided by the electric output of the facility. The formula for the Avoided Emissions Method is as follows:

$$\frac{\text{(Total GHG Emissions From Cogeneration Facility)} - \text{(Total GHG Emissions From a Proxy Steam Boiler)}}{\text{Electric Power in MWh Generated by the Cogeneration Facility}}$$

Sample calculations using this method are presented in Attachment 5.

4.9.2. Discussion

Based on the record in this proceeding, we conclude that the Conversion Method is the preferred approach to use for the interim EPS for the reasons discussed below.[141]

[141] We note that no party supports the Heat Rate of the Generator Method, only SDG&E/SoCalGas support the Avoided Emissions Method, and all other parties

Footnote continued on next page

We find the Heat Rate of the Generator Method to be incorrect as a simple matter of engineering. Specifically, it does not recognize that the thermal output (from the primary electric generation process) at a cogeneration facility will most likely be used directly as steam to do work, not converted into electricity in a secondary electric generation process that would incur the thermodynamic losses at the heat rate of the generator. In effect, using an electric heat rate to convert thermal energy output to kWh in this manner can double count the efficiency losses in the context of an output-based methodology.[142]

With respect to the Avoided Emissions Method, we concur with CCC, NRDC, TURN, DRA and others that this method is problematic for several reasons. First, as CCC points out, it may be very difficult to determine the characteristics of the stand-alone boiler whose GHG emissions are avoided by a cogenerator:

> "Is it the on-site boiler that the cogeneration unit replaced when it was first constructed? If the cogenerator or its thermal host continues to maintain an auxiliary boiler to provide steam when the cogeneration unit is down, is that the avoided boiler? Or is the avoided boiler a new, state-of-the-art boiler that the thermal host might use to replace the existing cogeneration unit?"[143]

Unraveling the answers to these questions during future power contract negotiations could end up being extremely complex and contentious. Moreover, the record in this proceeding does not provide us with a reasonable approach for

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commenting on this issue support the Conversion Method, i.e, CCC, CAC/EPUC, DRA, IEP, and NRDC/TURN/UCS/WRA (filing jointly).

[142] See *Opening Comments/Legal Brief on Final Workshop Report of NRDC/TURN/UCS and WRA*, October 18, 2006, p. 18.

[143] *Reply Comments/Brief of the CCC*, October 27, 2006, p. 4, footnote 4.

estimating the emissions from the boiler that would be utilized in the absence of cogeneration. As NRDC and others point out, SDG&E/SoCalGas' assumption of 80% efficiency for such a boiler is an arbitrary selection. The CEC data that SDG&E/SoCalGas suggest could instead be used to determine the general efficiency of gas boilers may not be representative of boilers located outside of California. In any event, it would be inaccurate to assume a general efficiency for all boilers since not all cogeneration facilities are gas-fired. Finally, with respect to SDG&E/SoCalGas' alternate suggestion that the boiler efficiency be set at the minimum state or local standards, we note that the cogeneration facilities under consideration are not necessarily new facilities. Therefore, we concur with NRDC, TURN, UCS and WRA that it would not be accurate to assume that the boiler that would have been used in its place would have efficiencies that meet current standards.

A comparison of the Avoided Emissions Method with the Conversion Method also reveals that the Avoided Emissions Method may effectively ignore important fuel savings benefits associated with cogeneration. Across the range of usable steam output in our examples (e.g., near zero to about 55 MMBtu), we observe that the amount of fuel consumed in an avoided emissions analysis is always greater at the same level of usable steam output, everything else being equal. This appears to be due, in large part, to the fact that the Avoided Emissions Method uses two different resources to produce two different products (electricity and steam), whereas cogeneration uses one process that captures the benefit of two products. As a result, the Avoided Emissions Method may calculate an emissions rate based on the use of more fuel than a cogeneration facility might otherwise use during its actual operation.

In contrast to the Heat Rate of the Generator Method, the Conversion Method represents an output-based method that appropriately recognizes that the thermal output of a cogeneration facility can be used directly as steam to do work, and not for the secondary production of electricity. Relative to the Avoided Emissions Method, the Conversion Method has the advantage of being more accurate in calculating the actual emissions rate of the cogeneration facility, since it takes into account the actual thermal output of the cogeneration facility. It also is easier to implement and administer because it does not involve making assumptions about the type of boiler "avoided" and associated emissions rates. Finally, as discussed above, the Conversion Method fully recognizes the fuel savings benefits associated with cogeneration. For these reasons, we adopt the Conversion Method of calculating cogeneration emissions rates for the purpose of determining compliance with the interim EPS.

In their comments, some parties who support the Conversion Method express concern over how it may be implemented. In particular, SCE contends that, as currently formulated by EPUC/CAC, the method does not take into account the losses from converting available thermal energy into "useful work." NRDC, TURN, UCS and WRA express concern that the EPUC/CAC proposed formula does not acknowledge that some of the "available" thermal output may be wasted (not "used") by the thermal host. These parties suggest that further clarifications or adjustments to the formula are needed to ensure that "the useful thermal energy employed for purposes other than the generation of electricity is factored into the calculation," as directed by § 8340(k).

We believe that these concerns can be addressed by using the FERC definition of "useful thermal energy" in its regulations mandating the minimum efficiencies of a QF, as recommended by EPUC/CAC. More specifically, FERC

defines a cogeneration facility as "equipment used to produce electric energy and forms of useful thermal energy (such as heat or steam)." The regulations also define "useful thermal energy" as:

> "(h) Useful thermal energy output of a topping-cycle cogeneration facility means the thermal energy:
>
> "(1) That is made available to an industrial or commercial process (net of any heat contained in condensate return and/or makeup water);
>
> "(2) That is used in a heating application (e.g., space heating, domestic hot water heating); or
>
> "(3) That is used in a space cooling application (i.e., thermal energy used by an absorption chiller)."[144]

By defining useful thermal energy in terms of its application to a productive industrial process, we concur with EPUC/CAC's observation that the FERC definition of "useful thermal energy output" includes only the thermal energy that is actually intended to be delivered to the thermal host (or in the case of bottoming-cycle cogeneration, first applied to the thermal application or process), and not any remaining thermal energy intended to be exhausted as waste heat. Moreover, it is also consistent with the plain meaning of "useful" that the FERC definition of "useful thermal energy" requires losses from converting available thermal energy into useful work to be taken into consideration when estimating/computing that value. Accordingly, in our rules

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[144] 18 CFR § 202(h). FERC regulations also refer to "useful thermal energy" in defining bottoming-cycle cogeneration facilities as follows: "Bottoming-cycle cogeneration facility means a cogeneration facility in which the energy input to the system is first applied to a *useful thermal energy* application or process, and at least some of the reject heat emerging from the application or process is then used for power production. (18 CFR § 292.202(e), emphasis added.)

we will clarify that the BTU THERMAL OUTPUT (expressed in kWh) in the adopted Conversion Method formula represents "useful thermal energy" output as defined in the FERC regulations implementing QF policy under PURPA.

With respect to the application of this formula to bottoming-cycle cogeneration, EPUC/CAC suggest that the energy input amounts for calculating the numerator ("total GHG emissions from cogeneration facility") should only reflect the amount of fuel associated with supplemental firing in the electric generating process, and should not reflect any of the "fuel in" (energy input) used in the underlying industrial process.[145] As we understand EPUC/CAC's argument, this is because if no supplemental energy is added to the waste heat to fire the generation, then there would be no electricity generated using this type of cogeneration technology, and therefore no emissions.[146]

However, if as EPUC/CAC suggest, only the energy input for supplemental firing for the electric generation is used to calculate the emissions levels in the numerator, we are left with a formula that divides this value by *both* the thermal energy output used for the industrial process *and* the electricity generation produced through the supplemental firing of the industrial process waste heat. We do not believe you can have it "both ways" – that is, only count the energy input for one of the co-generation outputs, but divide by both

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[145] Using Attachment 5, this would mean that the "fuel in" amount in Tables C and D for a bottoming cycle cogeneration would only reflect the amount of fuel associated with supplementary firing.

[146] See *Comments on Proposed Decision of EPUC/CAC,* January 2, 2007, pp. 12-13: "In a bottoming cycle unit, some of that waste heat is used to produce electricity. If no supplemental energy is added to the waste heat to fire the generation, then there are no additional emissions created in order to produce electricity."

outputs. Therefore, we reject EPUC/CAC's recommended clarification to the Proposed Decision. Instead, the Conversion Method formula should be applied to bottoming-cycle cogeneration as discussed in Section 4.9.1.1 above, and the "fuel in" should reflect the fuel used to produce the thermal energy output for the industrial process as well as any supplemental fuel used for supplemental firing.

Nonetheless, we do find EPUC/CAC's recommendation on how best to document the useful thermal energy output of cogeneration facilities at the EPS "gateway screen" to be reasonable and workable. Specifically, EPUC/CAC recommend that we take advantage of the existing documentation requirements of cogeneration facilities, noting that they are required to complete a questionnaire on an annual basis to demonstrate compliance with FERC efficiency requirements. On this form, the cogenerator presents monthly and annual values for energy input (therms), useful power output (kWh), and useful thermal energy output (MMBtu).[147] For the purpose of the interim EPS, we will calculate a cogenerator's emissions rates using the values presented in these questionnaires, which are readily available from the interconnected utility. For new cogeneration facilities, when this questionnaire has not been submitted to the utility, the emissions rate calculation will be based on readily available energy input, useful power output and useful thermal energy output information in FERC Form 556, required for QF certification.

We emphasize, however, that the above approach for calculating and documenting cogeneration emissions rates is adopted for the limited purpose of

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[147] See *Reply Comments of EPUC/CAC on the Final Workshop Report*, October 27, 2006. A copy of this questionnaire is attached.

demonstrating compliance with the interim EPS. Our determinations today are in no way intended to prejudge or predetermine the approach to be established in the context of our Procurement Incentive Framework or under the statewide GHG emissions limit envisioned under AB 32.

4.10. Emissions Rates for Renewables

In the draft report, staff recommended that all renewables, including those from biogenic sources, be assigned an emissions rate of zero. Staff recommended this approach after considering EPS goals, including administrative ease, as well as the data presented in comments on the net emissions rates of various renewable technologies.[148] In the final report, staff modifies this recommendation pointing to the statutory language of § 8341(d)(4), which states:

> "In calculating the emissions of greenhouse gases by facilities generating electricity from biomass, biogas, or landfill gas energy, the commission shall consider net emissions from the process of growing, processing and generating the electricity from the fuel source."

Based on the language of this section, staff concludes that any long-term commitment to renewables should "appear at the gate and file their applicable net emissions rate" before the Commission.[149]

All parties commenting on this issue disagree with staff's amended recommendations. They generally argue that SB 1368 provides the Commission with flexibility to make upfront determinations regarding the emissions rates of renewables, and to find them compliant with the EPS based on those

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[148] *Draft Workshop Report*, p. 29.

[149] *Final Workshop Report*, p. 36.

determinations. NRDC, TURN, UCS, WRA, SDG&E, SoCalGas, and PG&E point to the extensive analysis presented by GPI in its Phase 1 comments that, in their view, supports the following findings:

1) Many renewable generating sources operate without producing any GHG emissions at all, or levels of emissions much lower than the best available CCGT. This group of renewables includes geothermal, solar and wind.
2) Even without re-injection, the highest GHG emitting geothermal generators emit less than 100 lb (CO_2 equivalent/MWh, which is a fraction of the GHGs emitted by the most efficient CCGTs,
3) Solar thermal generators with full gas assist (up to 25 percent gas heat input) produce approximately 375 (CO_2 equiv) lb/MWh, still less than half the amount emitted by the most efficient CCGTs, and
4) When net emissions are accounted for, as required under SB 1368, generating electricity from biomass, biogas or landfill gas energy actually *reduces* the net GHG emissions associated with the disposal of society's waste and residue materials.

Attachment 6 summarizes the GHG emissions data filed by GPI. No party disputes the data or the conclusions drawn from it, as summarized above. Based on the record on net emissions rates of renewables, GPI, NRDC, TURN, UCS, WRA, SDG&E/SoCalGas, LS Power Generation (LS Power) and PG&E recommend that the Commission make a one-time determination in Phase 1 that renewables comply with the EPS.[150]

IEP generally concurs with this position, but presents an alternate recommendation for biogenic-based renewable technologies. IEP suggests that

[150] PG&E and LS Power would also extend this upfront approval to renewable resources firmed by a non-renewable resource. We address this separate issue in Section 4.7, where we consider the treatment of contracts with multiple resources or facilities.

the Commission adopt a pre-established calculation of net GHG emissions for each type of biogenic-based renewable technology that is likely to be subject to the EPS. These pre-approved emission calculations would then be used by the LSE when seeking approval for such projects.

We agree with GPI, NRDC, TURN and others that requiring the LSE to demonstrate compliance with the EPS for each and every long-term commitment with a baseload renewable resource would not further our policy objectives or those of the Legislature. Those stated objectives recognize that renewable resources are valued as being both environmentally and economically sound in the context of addressing the adverse consequences of climate change on the economy, health and environment of California.[151] In fact, SB 1368 echoes the policy expressed in the Energy Action Plan II that renewables (along with energy efficiency) are to be used to satisfy increasing energy and capacity needs *before* LSEs turn to fossil-fired generation.[152]

It is therefore fully consistent with these objectives to consider the approach recommended by these parties, that is, to issue an upfront finding in today's decision that renewable resources comply with the EPS. Moreover, if the record clearly demonstrates that these resources will pass the standard on a net emissions basis, it would be redundant and costly to require that LSEs demonstrate EPS compliance for each new ownership investment, new contract or renewed contract with renewables. Therefore, the general approach suggested by GPI and others would also enable us to reduce those costs, thereby reducing overall costs to electricity customers as well.

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[151] See SB 1368, Sections 1 (a)-(c), and also GHG Policy Statement, pp. 1-2.

[152] SB 1368, Section 1(d).

In its final report, staff expresses concern that SB 1368 may not permit the Commission to make an upfront one-time determination of EPS compliance for renewables. We find nothing in the statute that would preclude us from doing so. Section 8341(b)(1) directs that we shall not "approve" a long-term financial commitment by an electrical corporation "unless any baseload generation supplied under the long-term financial commitment complies" with the EPS. This language does not preclude us from determining, based on our consideration of these representative emissions rates, that specific baseload resources or technologies have emissions well below the EPS and should therefore be pre-approved as EPS-compliant. In fact, §§ 8341 (b)(3) and 8341(d)(6) require that we "establish procedures" to implement the EPS, and in doing so, § 8341(d)(6) also directs us to consider the effects of the standard on "overall costs to electricity customers."

For the reasons stated above, we find that the approach for finding renewables compliant with the EPS recommended by GPI, NRDC and others is both consistent with the language and intent of SB 1368, as well as reasonable in light of overall cost considerations. However, based on the record in Phase 1, we cannot make a blanket determination today that *all* renewable resources or technologies are EPS-compliant, as these parties suggest. This is because the evaluation of net emissions presented on the record and discussed in parties' comments did not consider several types of renewable resources or technologies, including hydroelectric, fuel cells, photovoltaics, biodiesel, and ocean thermal systems.

Nonetheless, as illustrated in Figure 1, the record clearly supports a finding that the net GHG emissions from the following renewable resources/technologies meet the interim EPS:

- Solar Thermal Electric (with up to 25% gas heat input)
- Wind
- Geothermal, with or without reinjection
- Generating facilities (e.g., agricultural and wood waste, landfill gas) using biomass that would otherwise be disposed of utilizing open burning, forest accumulation, landfill (uncontrolled, gas collection with flare, gas collection with engine), spreading or composting.

Consistent with the direction in SB 1368, the studies presented in the record calculated the emissions rates based on an evaluation of the net emissions resulting from the production of electricity.[153] In particular, for electricity generated from biomass, the studies considered the net emissions from "the process of growing, processing and generating the electricity from the fuel source," as directed under § 8341(d)(4). Appropriately, the calculations of net emissions considered both CO_2 and methane gases (on a CO_2 equivalent basis) to reflect the GHG emissions impacts associated with these processes.

The resulting calculations show that the net GHG emissions produced from the resources and technologies listed above are either zero, significantly less than today's adopted interim EPS standard, or even result in a net reduction in GHG emissions. This can be seen from the summary data presented in Attachment 6.

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[153] *Greenhouse-Gas Emissions From the Operation of Energy Facilities*, Pacific Institute Report, July 22, 1989 (Gleick, Morris and Norman); *Biomass Energy Production in California: The Case for a Biomass Policy Initiative*, November 2000, National Renewable Energy Laboratory Report No. NREL/SR-570-28805, (Morris), pp. 38-50. Summary data from these studies was submitted in GPI's July 27, 2006 post-workshop comments and the full text of the material referenced above was filed as attachments to the *Comments of the Green Power Institute on the Final Workshop* Report, dated October 18, 2006.

In particular, electric generation using biomass (e.g., agricultural and wood waste, landfill gas) that would otherwise be disposed of under a variety of conventional methods (such as open burning, forest accumulation, landfills, composting) results in a substantial *net reduction* in GHG emissions. This is because the usual disposal options for biomass wastes emit large quantities of methane gas, whereas the electricity production alternatives either burn the wastes that would become methane gas or burn the methane gas itself, generating CO_2. Since methane gas is on the order of twenty to twenty-five times more potent as a GHG than CO_2, and since methane has an atmospheric residence time of twelve years, after which it is converted to atmospheric CO_2, trading off methane gas for CO_2 emissions from energy recovery operations leads to a net reduction of the greenhouse effect.[154]

The record fully supports an upfront determination that the renewable resources and technologies listed above are EPS-compliant. In practice, this means that an LSE does not have to demonstrate compliance with the EPS for any long-term financial commitments with baseload generation utilizing these renewable resources and technologies. Such commitments get an automatic "pass through the EPS screen" without requiring calculations to demonstrate that the net emissions rate is below the EPS, or requiring that the LSE wait for

[154] For the biomass technologies identified above, which utilize landfill gas, agricultural and wood waste as the biomass fuel source, by definition there are no emissions associated with growing the fuel. An LSE entering into a long-term financial commitment with a biomass generating project where the growing the fuel is required will need to calculate net emissions taking into account the emissions associated with "growing," as well as "processing and generating" the electricity from the fuel source pursuant to § 8341(d)(4).

Commission approval of the proposed financial commitment, if such approval is required. (See Section 5 below.)

In their comments on the Proposed Decision, several parties suggest that the Commission establish additional proceedings or a process for adding to the above list of renewables that are pre-approved to be in compliance with the EPS. If and when there is sufficient data so that parties believe that the Commission could make such additional determinations, parties may file a Petition for Modification of this decision to augment the above list of pre-approved renewable resources and technologies.

4.11. Treatment of Null Renewable Power

There was considerable debate during workshops over how to attribute emissions factors to renewable resources that have sold off their renewable energy credits or "RECs." The term "null renewable power" refers to the power generated by those renewable resources that have transferred their renewable attributes through the trade or sale of RECs.

By way of background, the trading or sale of RECs may, under certain circumstances, provides a flexible compliance option to LSEs for meeting their RPS obligations, among other potential purposes. In California, LSEs are required to meet a minimum percentage of their load through RPS-eligible renewable resources. More specifically, electricity generated from eligible renewable resources must equal at least 20% of the total electricity sold to retail customers in California per year by December 21, 2010.[155]

[155] SB 107 (Stats. 2006, ch. 464).

A simplified example of a REC trade is depicted in Figure 2, where Utility B is procuring 10 MWs of power generated from a renewable resource, but does not need that amount to meet its RPS requirement, so it sells off the RECs to Utility A. Now the RPS obligation is met by each service territory, even though more of the renewable generation is located in service territory B.[156] This example illustrates how the trading of RECs can serve to even out geographic disparities in where renewable development can occur.

In their written comments in Phase 1, some parties recommend that the Commission allow renewables to be treated as renewable power in terms of emissions profiles, regardless of REC status. Others recommend that the treatment of renewable power should require a transfer of all renewable attributes associated with the generation of electricity from the facility to the purchasing LSE. Under this approach, which staff supports, the resulting null renewable power would be considered an "unspecified" resource and treated the same as an unspecified contract for the purpose of imputing GHG emissions. Still others recommend that the Commission not consider this issue now, as the appropriate treatment will depend on how the REC market develops in California.

In considering this issue, we note that there is no regulatory REC market in California at this time.[157] We have identified the investigation of a tradable

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[156] We recognize that this is a single, simplified example of how a REC trade would work, and that a future tradable REC system could apply to all RPS participants, generators and LSEs in the same service territory as well as different ones, and might be extended to allow non-RPS-obligated third parties, such as brokers, to buy and sell RECs.

[157] As the Center for Resource Solutions described in their October 27, 2006 Reply Comments on the Final Report, there is a voluntary market for RECs that is used by

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REC system as one of the tasks for R.06-02-012 and plan to initiate this investigation during 2007. This task will now necessarily include integration of the requirements of recently enacted SB 107 (Stats. 2006, ch. 464).[158] We therefore cannot predict at this time whether, how or when a REC market will develop in California. Therefore, there is some appeal to the suggestion of NRDC and others that we simply defer the issue of how to treat null power for the purpose of EPS compliance in today's decision.

However, deferring our consideration of this issue would introduce considerable uncertainty with respect to the treatment of renewables, with a potentially dampening effect on the development of these resources. For example, it would create uncertainty over whether a baseload renewable generator will pass or fail the EPS screen when a contract comes up for renewal if that generator sells off RECs in the meantime. We do not believe it serves the purpose of this proceeding, or our consideration of a future REC market, to leave these types of questions unanswered.

The fundamental issue we need to consider is this: Does it make sense to strip renewables of their GHG emissions attributes if RECs are sold when making the "go, no go" decision of whether an LSE can enter into a long-term financial commitment with that facility? We think the answer should be "no" for the following reasons.

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municipal utilities in California to supply their green pricing customers and by REC marketers to sell RECS on the national market. However, this is not the regulatory REC market that this Commission addresses in its proceedings.

[158] See D.06-10-019 in R.06-02-012, pp. 33-36.

First, stripping renewables of their emission profiles in this manner could easily create a "perverse" result in the context of EPS compliance, namely, it could discourage long-term commitments with renewable generators that have zero, low or even negative net GHG emission profiles in favor of resources with higher emissions rates. In the example depicted in Figure 2, the transfer of RECs from Utility B to Utility A simply determines where the *power produced* by the renewable resource is counted to meet RPS obligations. However, those desirable GHG emission profiles do not physically disappear from the facility with the transfer of the REC. The GHG emissions rate associated with the renewable facility under contract with Utility B continues to comply with the EPS, and renewing (or entering into a new) contract with that facility is preferable than entering into a long-term commitment with a baseload facility that may meet the EPS, but emits a higher level of GHGs than the renewable resource.

Moreover, in the context of EPS compliance, looking at the actual nature of the underlying powerplant even if RECs are sold does not create a double counting problem, as some parties suggest. This is because the EPS represents a "go-no go" standard for new long-term financial commitments separate from the RPS obligation to procure a minimum amount of electricity generation from EPS-eligible resources. As discussed above, each facility has to pass the EPS on its own emissions-generating merits, i.e., a high emitting facility would not be able to use a purchased REC for the purpose of reducing (or blending) its emissions to demonstrate compliance with the EPS. Therefore, there is nothing to double count here, since RECs would not have any value for EPS compliance under our rules. Moreover, our treatment of RECs in the context of a "go-no go" EPS compliance determination is not inconsistent with § 399.12, as amended by

SB 107, which provides that a REC "includes all renewable and environmental attributes associated with the *production* of electricity" (emphasis added), and not discrete investment decisions.

In contrast, in the context of an RPS program, the REC that is sold carries with it all the renewable attributes associated with the production of electricity so that another entity (LSE) can apply those attributes to meet its RPS obligations, which are also defined in terms of electricity production. In determining RPS compliance, double counting would occur if you let the REC "seller" also count those attributes towards its own RPS compliance.[159] If, down the road, RECs or similar instruments become tradable offsets for the purpose of meeting GHG emissions limits, then we will need to be very careful of potential double counting—just as we will for using tradable RECs to meet RPS obligations. But in the context of the interim EPS, we do not observe a double counting problem associated with our proposed treatment of null renewable power as long as RECs cannot be used to offset emissions for EPS-compliance purposes.[160]

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[159] In determining RPS compliance, double counting would occur if the REC "seller" (Utility B in the simplified example presented in Figure 2) also counted those attributes towards its own RPS compliance, after selling the RECs to another entity (Utility A in the Figure 2 example).

[160] The Center for Resource Solutions suggests in its comments that a double counting problem would arise in the context of the voluntary REC market in which green pricing customers buy RECs from (for example) a utility in California. In particular, they contend that if the REC were purchased from a facility that qualified for a mandate such as EPS based on being a zero emission facility, "the purchase of green pricing electricity would have no impact since it would have happened anyway." *Reply comments on final Workshop Report and Staff Recommendations Regarding the Greenhouse Gas Emissions Performance Standard of the Center for Resource Solutions*, October 27, 2006, p. 6. We fail to see how this represents a double counting problem since the voluntary purchasers of

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Third, in the EPS-compliance context, stripping renewables of their renewable attributes with the sale of RECs would create an inconsistent treatment of RECs between LSE-owned and non-LSE owned baseload renewable generation. This is because, as discussed in Section 4.2.3.1 above, LSE-retained generation is not generally subject to the EPS. So, if an LSE currently owns a baseload renewable generator, or builds one and passes the EPS at the "new plant construction" review point, the emissions from that generator will never be subsequently reevaluated as "null renewable power" if the LSE sells off the associated RECs.[161] However, if a third-party (non-LSE) does the same, the renewable facility will be reexamined and under staff's proposal imputed with an unspecified power emissions profile when the renewal contract comes up. Thus, the staff proposal could result in the emissions from two identical renewable baseload generators that sell off their RECs being valued very differently, depending upon who owns the generator.

Finally, as discussed at length in Section 4.12, there are considerable downsides to any approach presented in this proceeding for imputing emission factors to system purchases/unspecified power contracts. Even if we were inclined to impute null renewable power with something other than the facility's actual emissions, which we are not, we lack a reasonable method for doing so.

RECs are paying for the environmental benefits created by the *production* of renewable energy (not discrete investment decisions), and the RECs will still reflect those benefits as long as the facility continues to operate. In any event, as discussed above, today's adopted treatment of null renewable power does not result in double-counting problems for EPS compliance or in a regulatory REC market, which is the focus of this Commission's consideration of REC-related issues.

[161] Unless the LSE makes the types of renovations to plant that fall under the "new ownership investment" discussed in Section 4.2.3.2 above.

For all the reasons stated above, in applying the interim EPS we adopt today, the emissions of a renewable facility will not change if or when it sells RECs under a future regulatory REC market. Nor will RECs count towards compliance with the interim EPS by those LSEs who may purchase them for RPS compliance purposes in the future. However, we emphasize that today's determination on how to treat null renewable power and associated RECs is specific to the application of today's adopted interim EPS. This determination in no way guarantees that null renewable power will be assigned a zero or low GHG emissions value in the context of the Procurement Incentive Framework we are implementing in Phase 2 of this proceeding, or the statewide GHG emissions limits adopted by the Legislature in AB 32.

4.12. Consideration of Unspecified Contracts, including "Substitute Energy" Provisions

The staff workshop report defines "unspecified contracts" as those contracts/power purchases that are not linked to any particular generating source. Parties also refer to these types of contracts as "system energy" or "system power" contracts or purchase agreements, and we use these terms interchangeably in this decision. There was considerable debate during Phase 1 over whether to impute a specific emissions rate to unspecified contracts and, if so, what proxy rate to utilize for this purpose. The following approaches for imputing emissions rates were considered and discussed during the workshop process and in written comments:

a) Western Energy Coordinating Council (WECC) system average: Incorporates all generation activities throughout the western region.

b) WECC geographic average: Computes an emissions factor for all generation activities in various regions of the WECC system such as the Northwest, Southwest, etc.

c) CEC calculated "California Net System Power Average" or "California Net Power Mix": Represents the sources (e.g., coal, large hydroelectric, natural gas, nuclear, renewables) of electricity generated in California or imported to serve California customers that no retailer has identified through voluntary disclosure of specific purchases.

d) Coal emissions factor: would be based upon representative emissions from coal generation.

In written comments submitted after the workshop process, parties raise the issue of how to address "substitute energy" provisions under long-term contracts where the generating unit(s) are known ("specified" contracts), particularly in the context of firming deliveries from renewable resources. These contract provisions allow the seller to purchase energy from unspecified sources (also referred to as "system energy") to meet the contracted-for deliveries required under the unit-specified contract.

Below, we summarize staff's recommendations and the positions of the parties, followed by a discussion of our findings and conclusions.

4.12.1. Staff Recommendations

Based upon review of the data and parties comments, staff concludes that the WECC system average is generally not reflective of California activities or markets, and therefore should not be used to impute emissions rates for unspecified contracts. Staff rejects the use of WECC sub-regional geographic averages, since it would appear to penalize and reward LSEs differently based upon the major geographic source of their imported system power. Staff also rejects the use of coal as a proxy emissions factor, concluding that it is not an accurate reflection of the characteristics of all unspecified resources.

Staff recommends utilizing the California Net Power Mix information produced by the CEC as the basis for imputing GHG emissions rates to unspecified contracts. This calculation sums all in-state generation and electricity imports by fuel type and subtracts from this total: 1) electricity procured by retailers (California investor-owned utilities, public power and electric service providers) that they reported as "specified purchases" to the CEC and 2) electricity generated in California for use on-site rather than for retail sales.

The net result is a California Net Power Mix label that presents the percentage of power by fuel type (coal, large hydroelectric, natural gas, nuclear, renewables).[162] While reporting of specific purchases is voluntary, in order to make a claim that its mix of power is different from the California Net Power Mix, the retailer must disclose specific power purchases to their customers and to the CEC. The amount of electricity that retailers have elected *not* to disclose to their customers and to CEC (defined as "net system power") has declined over time as specific-purchase reporting in California has increased: In 1998, net system power represented 98 percent of retail electricity sales, while in 2005 it was less than 30 percent of the total.

In presenting its recommendation, staff acknowledges the concern raised by some parties that LSEs will be inclined to enter into unspecified contracts with

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[162] For 2005, the California Net Power Mix calculated by the CEC was as follows: Coal-38.5%, Large Hydroelectric-23.5%, Natural Gas-33.3%, Nuclear-0% and Eligible Renewables-4.7%. Keep in mind that this is different from CEC's calculation of the "gross system power," i.e., the fuel mix serving California load. The percentages above only reflect the fuel type break-downs for power that was not specified by retailers in their voluntary reporting to the CEC.

high emitting resources in order to circumvent the EPS by having a possible lower emissions rate imputed to that contract. However, staff anticipates that this will not be a substantial issue based on its understanding that long-term contracts with unspecified resources are at most a small fraction of the incremental power supply. Moreover, staff states that it will "monitor contracting patterns and behaviors to ensure that they do not change for this reason."[163]

4.12.2. Positions of the Parties

SDG&E/SoCalGas support the concept of using the California Net System Mix to impute the emissions profile for unspecified contracts, but only if the refined methodology proposed by CEC staff in May 2006 for the calculation of net system power is utilized for this purpose, rather than the current one. They argue that the refined methodology is appropriate because it results in imputed emissions that will enable unspecified contracts to pass the EPS, whereas the current one will not.

In contrast, Calpine, Sempra, PG&E and SCE, NRDC, TURN, UCS, GPI and WRA generally object to the use of the California Net System Mix, albeit for somewhat different reasons. NRDC, TURN, UCS and WRA argue that relying on any averaged emissions rate is problematic because it: 1) provides no information or guidance on the critical distinctions between emissions from different types of generating units, 2) invariably dilutes the emissions rates of the higher emitting sources and 3) could provide a significant loophole if the average rate enables all unspecified contracts to automatically pass the EPS.

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[163] *Final Staff Report*, p. 38.

To address these shortcomings, NRDC, TURN, UCS and WRA recommended in post-workshop comments and comments on the draft report that the Commission assign unspecified resource contracts the emissions level of a conventional pulverized coal generator. In their comments on the final report, these parties indicate that they are willing to support the use of the CEC Net Power Mix to calculate the emissions associated with unspecified contracts if the highest emissions rate for each fuel type is used in that calculation. Using the current 2005 California Net Power Mix, NRDC calculates that the result would be a weighted average emissions rate of 1,668 lbs CO_2/MWh. Sempra and Calpine argue that using any proxy for imputing emissions rates to unspecified contracts would not be consistent with the Commission's goals or SB 1368. Although long-term commitments may currently make-up only a small fraction of the incremental power supply, Calpine and Sempra submit that the use of a proxy that would assign a lower emissions level to a resource could encourage long-term commitments with resources that would otherwise not meet the interim EPS limit. To address unspecified contracts in a manner that is consistent with SB 1368, these parties recommend that the Commission require that all long-term commitments for baseload generation be made with "specified resources" that can demonstrate compliance with the interim EPS.

GPI supports the position of Sempra and Calpine. In GPI's view, their recommended approach avoids the potential precedent-setting effect any alternative treatment of unspecified power may have for the design of the state's long-term AB 32 greenhouse gas program.

SCE opposes both the use of the California Net Power Mix as well as the recommendation of Sempra and Calpine. In SCE's view, the former represents an arbitrary method to determine whether such contracts should pass the EPS,

and the latter fails to recognize that energy contracts without an upfront specified source are common transactions in the energy market today.

Instead, SCE recommends that LSEs be permitted to enter into a contract with a supplier with unspecified resources or facilities, and to provide documentation that shows the average emissions factor of that group of resources or facilities is lower than the rate used to impute emissions for unspecified contracts. If a system purchase is made, SCE recommends that this rate be based on the emissions of the system from which the purchase is being made, not the California Net System Mix. In the alternative, SCE recommends that the rate be based on the "default factor" used by the California Climate Action Registry (Registry) for calculating GHG emissions from the use of electricity. According to SCE, this factor is the average carbon intensity factor for the WECC California region, which is currently reflects "the average for Year 2000 egrid generators located in California, including imported energy."[164]

PG&E objects to using the California Net Power Mix, arguing that doing so has the potential to penalize or remove from California's resource mix system purchases that are otherwise clean, such as system imports from the Northwest. PG&E recommends that the Commission defer adopting a specific methodology for imputing GHG emissions from unspecified contracts until it can consider a more precise methodology, perhaps through a follow-up implementation workshop.

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[164] *Opening Comments of SCE on Final Staff Workshop Report and Proposal*, October 18, 2006, p. 11. See also *Reply Comments of SCE on the Final Staff Workshop Report*, October 27, 2006, pp. 10-11.

However, should the Commission adopt the position of Calpine, Sempra and GRI on the issue of unspecified contracts, PG&E requests that the EPS rules clarify that this would not preclude the use of substitute energy, which PG&E asserts is commonly permitted in unit-specific contracts with both non-renewables and renewables contracts.[165] PG&E asserts that such contracts often contain substitute energy provisions whereby some portion of the energy delivered would not necessarily come from the specific unit, but instead from unspecified sources. PG&E proposes that the EPS rules maintain contracting flexibility over a contractually specified time period for the use of substitute energy to support contracts covered by the EPS, but to impose contract restrictions as outlined in the table below (Table A):

Table A – Proposed Restrictions for Substitute Energy in Energy Transactions Covered by the EPS

Transaction Type	In-Area	Imports
Renewable and Non-Renewable (Unit Specific, RPS eligible if renewable)	Substitute energy limited to 15% of forecast energy production if either Condition A or Condition B is met	Substitute energy limited to 15% of forecast energy production if either Condition A or Condition B is met
Non-Unit Specific or System Energy	Cannot do these transactions	Cannot do these transactions

Condition A: A contract that permits the seller to provide system energy under a unit specific contract when the unit is unavailable due to a forced outage, scheduled maintenance, or other temporary unavailability for operational or efficiency reasons.

[165] *Opening Comments of PG&E on Proposed Decision*, January 2, 2007, pp. 3-7.

Condition B: A contract that permits the seller to provide system energy under a unit specific contract to meet operating conditions required under the contract, such as provisions for number of start-ups, ramp rates, minimum number of operating hours, etc.

In reply comments, GPI support PG&E's proposed clarification with respect to firming renewables. In GPI's view, this approach represents a "properly structured" firmed renewable contract, in that firming is used to accommodate short-term unpredictable variations in renewable output that is sufficiently limited and, by its nature, will be purchased in the form of as-available, short-term system power.[166] Several additional parties, including NRDC, TURN, SDG&E and Sacramental Municipal Utility District (SMUD) also find the PG&E proposal to be reasonable in principle for unit-specific contracts, but express some reservations or suggest modifications. In particular, NRDC, TURN, UCS and WRA caution that any provision for the use of substitute energy should ensure that the 15 percent cap is truly a ceiling, and not a targeted level, and that the use of substitute system power be limited to event-driven, temporary circumstances. SDG&E and SoCalGas suggest that a higher percentage limit (25%) would be more consistent with the RPS eligibility criteria for hybrid systems.

SMUD expresses concern that the PG&E proposal would not adequately address the inherent difficulties associated with limiting firming power for "intermittent" renewable resources (e.g., wind)[167] and presents two alternative

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[166] *Reply Comments of the GPI on the Proposed Decision*, January 8, 2007, p. 2.

[167] Wind and solar are considered "intermittent" generating sources because the output is controlled by the natural variability of the energy resource. Intermittent output usually results from the "direct, non-stored conversion of naturally occurring energy fluxes such as solar energy, wind energy, or the energy of free-flowing rivers" (that is,

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options for Commission consideration in its comments on the Proposed Decision. Under the first option, the EPS rules would allow contracts for renewable power to be firmed with substitute system purchases but limit the total power purchased to the expected output of the renewable resource. Under the second option, the EPS rules would permit contracting for a fixed delivery amount equal to 80% of the maximum rated capacity of the renewable facility, allowing the purchasing entity to procure substitute energy as needed to meet the contracted level.[168]

More generally, in their comments on the Proposed Decision, SMUD, CMUA and Barclay et al.[169] argue that restrictions on long-term contracts with unspecified contracts create adverse impacts that the Commission must consider. In particular, Barclay et al. argue that such restrictions arbitrarily eliminate power marketers from competition, thereby depriving California consumers of the benefits of their lower cost options. These parties also contend that relying on unit-specific long-term contracts will have an adverse impact on market liquidity and contract reliability. Finally, SMUD also argues that requiring all long-term contracts to be only with specified, unit-contingent resources would

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run-of-river hydroelectricity). [See www.eia.doe.gov/glossary/glossary_i.htm] In contrast, the output from a "dispatchable" renewable generator (e.g., those fueled by geothermal or biomass) can be controlled by the operator to meet system requirements, usually by regulating the flow of the fuel.

[168] See *Comments of SMUD on the December 13, 2006 Proposed Decision*, January 2, 2007 pp. 9-10 and *Reply Comments of SMUD on the December 13, 2006 Proposed Decision*, January 8, 2007, pp. 2-4.

[169] Barley et al. refers to the following organizations that jointly filed opening comments on the Proposed Decision: Barclay's Capital, J. Aron & Company, Morgan Stanley Capital Group.

adversely impact the resource procurement programs of publicly-owned utilities and their ability to reliably serve load at stable prices.

4.12.3. Discussion

SB 1368 provides the following general guidance on the issue of how to address unspecified contracts:

> "In developing and implementing the greenhouse gases emission performance standard, the commission shall address long-term purchases of electricity from unspecified sources in a manner consistent with this chapter."[170]

In order to comply with SB 1368's mandate that we address unspecified sources in a manner consistent with the rest of the statute, we believe that our EPS rules should ensure that:

> (1) LSEs only enter into long-term financial commitments with baseload generation that comply with the EPS, and
>
> (2) EPS compliance cannot be achieved in a manner that would yield a contrary result, i.e., that results in an increase in long-term commitments with high-emitting sources.

Based on the record in this proceeding, we conclude that imputing emissions rates to unspecified contracts, would not be consistent with SB 1368 for several reasons. First, we have difficulty reconciling the concept of imputed emissions rates with the requirements of SB 1368 since, by definition, such proxies do not reflect the actual emissions from the underlying resources. As a result, using imputed rates does not permit us to determine whether a commitment with an unspecified resource is consistent with the Commission's

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[170] § 8341(d)(7). We find no further discussion of unspecified contracts in the statute or legislative history.

goals or SB 1368 or simply exacerbates the problems the Commission and the Legislature are trying to address.

Moreover, any method to impute a GHG emissions rate to unspecified resources results in a binary outcome in the context of an EPS—that is, all financial commitments with unspecified resources will either "pass" or "fail" based on the selected level of imputed emissions. As a result, there is enormous pressure to game the methodology and input assumptions used for this purpose, thereby making it very difficult and contentious to implement this particular approach to addressing unspecified contracts.[171]

Not surprisingly, parties have generally lined up behind this issue based on whether they want "all" unspecified contracts to pass the EPS screen or "none" of them to pass. For example, NRDC originally proposed that the emissions of pulverized coal plants be used to impute emissions for unspecified contracts, an approach that would clearly result in none of them passing the EPS

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[171] In its comments on the Proposed Decision, SMUD argues that the resource mix for each system where unspecified power originates should be analyzed and a determination made of whether the mix of resources meets the EPS, thereby avoiding the binary outcome described above. *Comments of the SMUD on the December 13, 2006 Proposed Decision,* January 2, 2007, pp. 8-9. We fail to see how a binary outcome can be avoided under the approach SMUD suggests, since any contract procuring unspecified power from a particular originating system would still face either a "no go" or "go" outcome depending on the relative level of high- and low-emitting resources in that system's resource mix. Moreover, SMUD's proposed approach does not address the fundamental difficulty we have with permitting unspecified contracts as a general rule under the interim EPS, since we still would not know whether the deliveries will actually come from the high-emitting facilities in the system's resource mix, or not. Nor does it recognize that the statutory deadline for our adoption of an "enforceable" EPS is February 1, 2007, which does not provide sufficient time to conduct the analysis and reach the determinations SMUD suggests should be undertaken for each potential originating system of unspecified power that LSEs procure from.

screen. NRDC now indicates qualified support for using the California Net Power Mix, but only if the very highest emissions rates for each technology is utilized. By NRDC's own calculation, this would have the same result: None of the unspecified contracts would pass the EPS screen.

On the other hand, SoCalGas and SDG&E support the use of the California Net Power Mix, but only if the revised version under consideration by the CEC staff is used. When coupled with mid-range emissions rates for each technology, this approach would permit all unspecified contracts to pass the EPS screen.

As DRA illustrates at some length in its comments, there are also various input assumptions associated with calculating an imputed emissions value using any proxy resource mix (California Net Power Mix, WECC system purchases, or others) that could be manipulated to "push" an unspecified contract through the EPS gateway, such as the use of full load heat rates versus heat rate ranges under less than full-load conditions.[172]

SCE's recommendation also has the potential to push an unspecified contract through the EPS gateway, since the proposed default rates are based on broad geographic averages that would permit high emitting resources to pass the standard. Moreover, under SCE's proposal, the case-by-case review would be one-sided: The Commission would be asked to grant an exception to the imputed emissions value only in those instances where the power is being purchased from a group of very low emitting resources (e.g., a group of all hydroelectric powerplants), but not when the opposite may be true.

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[172] *Opening Comments and Legal Argument of the Division of Ratepayer Advocates on the Final Workshop Report on Phase 1 Issues*, October 18, 2006, pp. 5-7. As DRA points out, under less than full-load conditions, one can expect the corresponding heat rates to go up, and therefore result in higher emission values.

Finally, none of the specific proxy approaches recommended by staff or in parties' comments are reasonable or workable for our purposes, at least not at this time. As staff points out, the WECC system average is generally not reflective of California activities or markets, and the use of WECC sub-regional geographic averages would also dilute the impact of high-emitting resources, allowing them to automatically pass through the GHG screen. Similarly, the WECC California region average metric suggested by SCE in its October 18, 2006 comments represents a broad statewide average that does not distinguish among different types of generating resources on the basis of their relative GHG emissions. It is also too broad a metric for the purpose of establishing whether an unspecified contract is EPS-compliant or not.

As discussed above, staff and some parties propose that we utilize the California Net Power Mix as a proxy for the resource mix associated with unspecified contracts for the purpose of evaluating EPS compliance. We note that this mix was developed by the CEC for a very different purpose (power content labeling), and has not been revised, updated or endorsed by the CEC for use in imputing GHG emissions under SB 1368 or in any other GHG emissions policy context.

Moreover, there is no clear conceptual link between this metric and the mix of resources that might underlie unspecified contracts now or in the future, even on a system-wide average basis. The calculation is based on what is left over after the amounts that retailers voluntarily report as the resources underlying their short- and long-term power purchases (and accounting for on-site generation). It was developed to encourage retailers to disclose their actual power mix to customers. For that purpose, the CEC reports that power content labeling has been successful since the amount of net system (unreported) power

has decreased significantly since its inception. Nonetheless, we do not find a reasonable conceptual correlation between this metric and the resource mix that might underlie unspecified long-term contracts.

For the reasons discussed above, we find that adopting an approach to unspecified contracts that involves the use of proxy estimates for emissions rates would not further the goals of SB 1368 and would be problematic from an implementation standpoint.

That brings us to the approach recommended by Sempra and Calpine, namely, to require under our rules that all long-term commitments for baseload generation be made with "specified resources" that can demonstrate compliance with the interim EPS. This approach is fully consistent with SB 1368 since it ensures that "any" and "all" long-term financial commitments with baseload generation will meet the EPS, as the statute so directs.[173] Moreover, it cannot be gamed in a manner that could result in the opposite outcome than the statute intended, i.e., an increasing number of long-term commitments to high emitting resources. Although SCE argues that this approach would deprive LSEs of needed flexibility in resource procurement, thereby increasing costs to ratepayers, this assertion is simply not supported by the record.

Throughout the workshop process, attendees indicated that the LSEs would be entering into very few, if any, new contracts or contract renewals with unspecified contracts with a term of five years or greater. At the assigned ALJ's direction, SCE, SDG&E and PG&E submitted data on how many contracts of five years or more for unspecified power they (1) actually entered into during 2004

[173] Indeed, it could be difficult in the case of an "unspecified contract" even to devermine whether any "baseload" powerplant is being used to generate the power.

and 2005 and (2) planned to enter into over the 2006-2008 period. These utilities also provided data on the amount of unspecified power they have purchased and plan to purchase under short- term contracts (less than five years).

All three utilities responded that they did not enter into any contracts of five years or more for unspecified resources in 2004 and 2005, and do not anticipate entering into any contracts with unspecified resources with a term of five years or more in the 2006-2008 period. In contrast, all three utilities entered into numerous contracts with *short-term* unspecified contracts during 2004-2005, which is to be expected given the type of energy products offered under them.[174]

In sum, the record shows that it is highly unlikely that the LSEs will be entering into any new or renewal power purchase contracts of five years or greater that are unspecified during the transition to a statewide GHG emissions limit. Therefore, requiring that long-term contracts with baseload generation be "specified" so that EPS compliance can be demonstrated should not have a significant, if any, impact on an LSE's resource procurement flexibility.[175]

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[174] "Contracts with unspecified resources are for energy products whose offered prices are valid for a very short period of time. This is due to the fact that energy prices fluctuate constantly, in part due to fluctuations in commodity prices of natural gas as well as underlying market conditions. SCE has to decide whether to buy or not to buy such energy products in a very short period of time.... As a result, SCE is currently limited to soliciting contracts of energy products, including such contracts with unspecified resources, to those with durations less than five years consistent with its current procurement authority." See *SCE Greenhouse Gas Emission Standards Data Response*, October 18, 2006, Response to Question 03, posted at http://www.cpuc.ca.gov/static/energy/electric/climate+change/.

[175] During our interagency consultations on SB 1368, CEC staff has indicated that the publicly owned electric utilities may not be similarly situated, i.e., they have entered into a significant amount of contracts of five years or greater with unspecified power in recent years and may be planning to do so in the future. Nothing in today's decision is intended to suggest that the CEC may not consider unique circumstances facing these

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Moreover, it is our understanding from consultations with the ISO staff that for the ISO's system reliability determinations, the ISO relies on specific information about the plant facility and its location within the ISO control area. Therefore, the requirement to specify the resources underlying long-term contracts for the purpose of demonstrating EPS compliance is consistent with the type of information that the ISO also requires for these reliability determinations.

A requirement that long-term power purchase contracts specify the underlying generation facilities is also consistent with our discussion of emissions registration in D.06-02-032 and represents a logical interim step towards the implementation of AB 32.[176] Under that new law, CARB is required to establish the state's mandatory GHG reporting and verification program by January 1, 2008. At that point, all power contracts will need to provide verifiable GHG emissions documentation. To permit LSEs to enter into new or renewed long-term unspecified contracts with high GHG-emitting facilities through the use of an imputed emissions value for system power in the meantime could put them, and their customers, in a vulnerable position when these reporting requirements take effect in 2008 for the implementation of the statewide, load-based GHG emissions limits.

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entities with respect to how an EPS that will apply to them should address unspecified contracts. However, we believe that the policy, legal and implementation issues associated with imputing emission rates to unspecified contracts and permitting substitute energy purchases under long-term contracts discussed in today's decision will need to be carefully considered as the CEC develops an EPS that is consistent with the statute as well as today's adopted EPS, as directed by SB 1368.

[176] D.06-02-032, pp. 47-48.

As Sempra points out, other jurisdictions have developed specific resource tagging mechanisms to track generation attributes, including GHG emissions, of resources within their control areas.[177] In particular, PJM Interconnection utilizes the Generation Attribute Tracking System and ISO New England utilizes the Generation Information System for this purpose.[178] In our view, it is entirely feasible to implement a program that tracks the GHG emissions of all generating units, and that would enable marketers and other sellers of unspecified resource contracts to assign a reasonable and accurate GHG emissions profile to their contracts. Over time, this should be the strategy pursued by California to deal with emissions from any unspecified resource contracts that LSEs may wish to pursue; however, as the record shows, this is not a likely pursuit for the types of LSE long-term procurements subject to the EPS.

For the reasons discussed above, we will require that all long-term commitments be with specified sources that can demonstrate EPS compliance (or demonstrate that compliance is not required), except when substitute system energy is purchased to firm deliveries from specified powerplants under the limited conditions we describe below. In response to comments on the Proposed Decision,[179] we also clarify that the following circumstances would comply with

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[177] *Comments of Sempra Global on Draft Workshop Report*, September 8, 2006, p. 6.

[178] PJM Interconnection is the regional organization that monitors and coordinates movement of wholesale electricity over a 56,000-mile section of the power transmission grid that spans across 13 northeastern and midwestern states and the District of Columbia. ISO New England serves similar functions across all of the New England states as the California ISO.

[179] See, in particular, *Reply Comments of DRA on the Phase 1 Proposed Decision*, January 8, 2007, p. 2 in response to *Comments of SMUD on the December 13, 2006 Proposed Decision*, January 2, 2007.

our EPS rules: First, if the long-term contract specifies that power will be delivered exclusively from pre-approved renewable technologies or resources, and there are assurances in the contract to that effect, then the contract would comply with the EPS even if none of the generating sources are specified. Second, if a group of powerplants from which power will be delivered under a contract is specified, and there are assurances in the contract that deliveries will only be from one or more of the powerplants in that group *and* each of those that are baseload powerplants would individually pass the EPS, then the contract would comply with the EPS. The burden is on the LSE to provide sufficient documentation to demonstrate compliance with the EPS under these circumstances.

In its comments on the Proposed Decision, SMUD argues that if the Commission bans all long-term contracts without a specified unit, it will have failed to follow the requirement of SB 1368 to "address" unspecified contracts, thereby violating the rules of statutory construction.[180] We disagree. As noted above, § 8341(d)(7) of SB 1368 requires the following with respect to unspecified sources:

> "In developing and implementing the greenhouse gases emission performance standard, the commission shall *address* long-term purchases of electricity from unspecified sources in a manner consistent with this chapter. "

The word "address" is commonly understood to mean to turn one's attention to, deal with, or treat.[181] Therefore, we read the phrase "the

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[180] *Comments of SMUD on the December 13, 2006 Proposed Decision*, January 2, 2007, p. 3.

[181] Merriam-Webster online dictionary at www.m-w.com/dictionary/address.

Commission shall address" in the context of §8341(d)(7) to mean that the Commission shall *direct its attention to, deal with, or treat* the subject of long-term purchases of electricity from unspecified sources. By requiring that the Commission "address" a specific topic the Legislature is not directing the Commission towards any particular determination.

To the contrary, the Legislature here has chosen to leave open the question of *how* to treat unspecified contracts to the Commission. It does not, as SMUD asserts, require that we allow long-term commitments with unspecified resources under the interim EPS. Nor does it prevent us from deciding that imputing an emissions rate for such contracts is unworkable or inconsistent with the objectives of SB 1368. Accordingly, we conclude that prohibiting LSEs from entering into long-term contracts for unspecified power is consistent with the Legislature's requirement that the Commission "address" the subject of unspecified sources with respect to the EPS and, for the reasons discussed at length above, that our treatment of unspecified contracts is consistent with "this chapter."

Nonetheless, we are persuaded by the comments of GPI and others on the Proposed Decision that providing for *limited conditions* under which system energy can be purchased to firm deliveries under long-term contracts is consistent with the overall objectives of SB 1368. As PG&E and other point out, many new renewable resources cannot by themselves meet the energy profile needs of LSEs without having backup access to flexible and firm system purchases. Completely prohibiting unspecified resources that are used for this purpose could therefore undermine the policies of California to increase reliance

on renewable energy resources and thereby exacerbate the problems that the interim EPS is intended to address.[182]

PG&E's proposal would limit substitute system energy purchases by both (1) restricting the level of substitute energy purchases to no more than 15% of forecast energy production over the contractually specified time period and (2) specifying that such system purchases can only be made under event-driven conditions that are of limited duration. We agree with PG&E that this restricted use of substitute system energy is very unlikely to result in intentionally sourcing energy from high carbon intensive baseload resources, particularly because substitute energy events are often unpredictable and therefore "no new high-carbon generation will be built solely to provide substitute energy at the 15% level."[183] Moreover, as PG&E and others points out in their comments on

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[182] See SB 1368, Section 1 (c) and (d).

[183] *Opening Comments of PG&E on Proposed Decision*, January 2, 2007, pp. 5-6. In their joint reply comments, NRDC, TURN, UCS and WRA argue that the conditions as currently written could create "an avenue to build in system power into a long-term unit-specific contract." *Reply Comments of NRDC/TURN/UCS and WRA*, January 8, 2007, pp. 2-3. We fail to see how PG&E's proposed language for Conditions A and B, in combination with the 15% cap on permitted system purchases could lead to such a result. Moreover, we do see great difficulty in trying to distinguish between the limited use of system power for conditions that are "event driven" versus "due to economic considerations" as these parties suggest. Therefore, we retain PG&E's proposed language for these conditions.

We also do not find merit to SDG&E/SoCalGas' suggestion that PG&E's proposal be modified to allow substitute energy purchases up to 25% of in order to be consistent with CEC's RPS eligibility guidelines for "hybrid systems." SDG&E/SoCalGas' reference to the 25% number in the RPS guidelines is taken out of context. Under certain circumstances, the RPS guidelines allow up to 25% of non-renewable resources in the context of the fuel use for a specific facility (e.g., for solar thermal generators), but not in the context of substitute system purchases. Moreover, the RPS guidelines specifically state that RPS eligibility is not permitted for any fossil-fuel portion of any

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the Proposed Decision, the ability for a seller to substitute energy from the marketplace on a short-term basis is an important feature of a long-term contract because it enables better management of operating and financial risk that can provide greater performance assurance at a more moderate price to ratepayers.[184]

However, we take issue with PG&E's proposal in one respect. As SMUD points out in its reply comments on the Proposed Decision, PG&E's proposal for limiting substitute energy purchases does not adequately recognize the unique characteristics of intermittent renewable resources, in particular wind generators. Unlike dispatchable renewable resources, such as biomass and geothermal, actual deliveries from intermittent renewable resources will fluctuate below the expected average output of the facility based on the natural and unpredictable variability of the energy resource, not just the event-driven conditions described under PG&E's proposal. Moreover, actual deliveries from intermittent resources will also fluctuate above the expected average output of the facility based on the unpredictable variability of the energy resource. As a result, there are both increments and decrements to the level of system energy associated with firming an intermittent renewable resource, which is not adequately recognized under PG&E's proposal.

This can be illustrated in the following (very simplified) numerical example: A wind generator with a long-term contract to deliver 40 MWh may sometime produce 25 MWh and sometimes produce 70 MWh. In any event, the

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new or repowered non-QF facility. (See CEC-300-2006-007-F, Renewable Energy Program, "Renewables Portfolio Standard Eligibility Guidebook," April 2006, pp. 16-17.

[184] See, for example, *Opening Comments of PG&E on Proposed Decision*, January 2, 2007, p. 5 and *Comments of SMUD on the December 13, 2006 Proposed Decision*, January 2, 2007, p. 10.

buyer withdraws 40 MWh from the grid on an hourly basis. In those hours that the wind generator is producing 25 MWh, the wind generator (seller) will need to purchase 15 MWh of substitute system energy to meet the terms of the contract. Emissions during these hours are positive, but unknown, as the source of the 15 MWh is unknown. When the wind generator is producing more than 40 MWh (e.g., 70 MWh in this example) however, it displaces 30 MWh of system power with power generated from the renewable resource. In other words, there are both increments and decrements to unspecified system energy associated with firming an intermittent renewable resource due to the unique characteristics of such resources. Deliveries from dispatchable renewable resources, such as geothermal and biomass, on the other hand, create "increments" to system energy purchases under the types of event-driven conditions described in PG&E's proposal, but do not also produce the offsetting "decrements" to the levels of system energy described above.

Therefore, whereas PG&E's proposal appropriately restricts the use of substitute energy purchases in the context of dispatchable resources, we believe that SMUD's comments suggest a more appropriate approach to limiting substitute system energy purchases under long-term contracts with intermittent renewable resources. In particular, SMUD's first option recognizes that if the amount of substitute energy purchases is limited so that total purchases under the contract do not exceed the expected output of the intermittent renewable resource, we would expect those increments and decrements to average out to zero on balance. This approach provides the type of contracting flexibility and practicality that SMUD and others argue is uniquely required for long-term contracting with intermittent renewable resources, without creating a loophole

or exception to the general rule on unspecified contracts that would be contrary to the intent of SB 1368.

In contrast, we find that SMUD's second option could undermine the objectives of SB 1368 by, in effect, permitting system purchases to equal far more than the expected output of intermittent renewable resources. As discussed above, under this option the LSE could contract for a fixed delivery amount equal to 80% of the maximum rated capacity of the renewable facility, allowing the purchasing entity to procure substitute energy as needed to meet the contracted level. By linking the levels of substitute energy purchases to a percentage of rated capacity that is high relative to the expected output of such intermittent resources, this approach results in "increments" to unspecified system power purchases that can be expected to significantly and regularly exceed the "decrements" to system power over the life of the contract.[185] As a result, this approach has the potential to create a significant loophole to our general rule for unspecified contracts that would permit LSEs to enter into long-term contracts with high-emitting resources, yielding a result that is contrary to the intent of SB 1368.

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[185] As GPI and others recognize in their reply comments on this issue, the second option put forth by SMUD is likely to permit up to 50% of deliveries under the contract from unspecified system substitute purchases for wind resources. Put another way, with wind facilities generally delivering on average 35-40% of their rated capacity, allowing substitute energy purchases up to 80% of the rated capacity means that, on average, unspecified resources would comprise about the same level of energy delivered under the contract as the energy delivered from the wind generator. As a result, there would be a significant net "increment" to system purchases permitted under these provisions that would not be offset by the normal fluctuations of the intermittent resource around the average expected output of the facility, as there would be under SMUD's option #1.

In sum, we modify the Proposed Decision to permit LSEs to enter into contracts with a term of five years or longer that include provisions for substitute energy purchases from unspecified resources ("system energy") under the following circumstances:

1. The contract is with one or more specified powerplants, each of which is EPS-compliant under our adopted rules.
2. For specified contracts with non-renewable resources or dispatchable renewable resources (or a combination of each), substitute energy purchases for each specified powerplant are permitted up to 15% of forecast energy production of the specified powerplant over the term of the contract, provided that the contract only permits the seller to purchase system energy under either of the following conditions:
   a) The contract permits the seller to provide system energy when the specified powerplant is unavailable due to a forced outage, scheduled maintenance or other temporary unavailability for operational or efficiency reasons; or
   b) The contract permits the seller to provide system energy to meet operating conditions required under the contract, such as provisions for number of start-ups, ramp rates, minimum number of operating hours, etc.

   A "dispatchable" renewable resource for the purpose of this rule is one that is not defined as "intermittent" under section 3 below.
3. For specified contracts with intermittent renewable resources (defined as solar, wind and run-of-river hydroelectricity), the amount of substitute energy purchases from unspecified resources is limited such that total purchases under the contract (whether from the intermittent renewable resource or from substitute unspecified sources) do not exceed the total

expected output of the specified renewable powerplant over the term of the contract.[186]

The burden is on the LSE to provide sufficient documentation in compliance submittals to demonstrate that the above requirements are met. In particular, the LSE is required to make available to Commission staff the source data and methodology it uses in developing the level of expected output from renewable resources under contracts with a term of five years or longer that permit substitute energy purchases from unspecified resources, in order to demonstrate that the limits for substitute energy purchases for both intermittent and dispatchable renewable resources were properly established under the substitute energy provisions.

As discussed above, several parties urge us to permit long-term contracts with unspecified contracts under a broader range of circumstances than those permitted under the Proposed Decision. We have carefully considered their concerns in today's decision, and made modifications to the Proposed Decision that we believe can address those concerns and still be consistent with the legal and policy directives of SB 1368. In particular, as SMUD and DRA point out, the EPS rules should recognize that a long-term contract with a group of resources that may not specifically identify the units that will be delivering power should, under certain circumstances, be permitted--and we have clarified those circumstances in today's decision. Further, as SMUD, PG&E, GPI and others

[186] SMUD also recommends that the utility be required to purchase the RECs associated with the renewable generating unit. In Section 4.11, we address the issue of null power and RECs in the context of today's adopted interim EPS. In light of that discussion, we find SMUD's suggestion that such a requirement be imposed on LSEs (if and when a regulatory REC market exists in California) to be premature for our Phase 1 determinations, and therefore do not adopt it.

point out, the Proposed Decision's restrictions on purchases from unspecified resources does not adequately address the issue of substitute energy purchases under long-term contracts with specified powerplants, particularly for renewable resources.

As discussed above, we have carefully considered the suggestions for addressing this issue and have modified the Proposed Decision to provide additional contracting flexibility to the extent that we believe is consistent with the intent of SB 1368. In addition, in recognition of the reliability concerns raised by several parties in this proceeding, including Barclay et al., our EPS rules permit LSEs to request Commission consideration of a reliability exemption, on a case-by-case basis, in the event that an LSE must enter into a long-term unspecified contract to address system reliability concerns. (See Section 4.8.5.) Moreover, LSEs will continue to be able to enter into short- and intermediate term contracts with all types of resources, including unspecified resources if needed for reliability or economic purposes.

In its comments on the Proposed Decision, SMUD requests that we also make findings that would recognize differences in the procurement practices between publicly-owned utilities and LSEs, and specifically reflect those differences in today's adopted rules regarding purchases from unspecified resources.[187] However, the CEC—not this Commission--is responsible for adopted EPS rules that will be applicable to SMUD and other publicly-owned utilities. We reiterate that nothing in today's decision is intended to suggest that the CEC may not consider unique circumstances facing these entities with

[187] *Comments of SMUD on the December 13, 2006 Proposed Decision*, January 2, 2007, p. 6.

respect to how an EPS that will apply to them should address purchases from unspecified resources. Nonetheless, we do believe that the policy, legal and implementation issues associated with imputing emission rates to unspecified contracts and with permitting substitute energy purchases under long-term contracts discussed above are relevant to the CEC's rulemaking. We therefore expect that these issues will be considered in consultation with this Commission as the CEC develops an interim EPS for publicly-owned utilities that is consistent with today's adopted EPS, as directed under § 8431(e)(1) of SB 1368.

5. Compliance-Related Issues

The concept of a "gateway screen" approach to EPS compliance is an integral component of staff's recommendations and is supported by all parties. Under this approach, a series of questions or criteria are applied to first determine whether or not the LSE's financial commitment is a "covered procurement" subject to the EPS. If it is, then the commitment is screened to ensure that the associated GHG emissions rate does not exceed the adopted EPS performance level of 1,100 lbs of CO_2 per MWh. Once the financial commitment successfully passes through the gateway screen, the LSE has demonstrated EPS compliance for that particular commitment. Ongoing Commission review or monitoring of the facilities underlying that commitment is not required.

We adopt this approach for demonstrating compliance with the interim EPS. We believe it is consistent with the intent of SB 1368, which directs us to look to the "design and the intended use" of the powerplant under § 8340(a). Moreover, as staff and the parties point out, a gateway screen approach is the most practicable and enforceable manner in which to determine EPS compliance.

While parties agree on the concept of a gateway screen approach to determining EPS compliance, there is some disagreement on what compliance

submittals should be required of different types of LSEs (i.e., large electrical corporations, small electrical corporations, energy service providers, community choice aggregators), as well as what documentation those submittals should contain. There is also disagreement among some parties on how to interpret SB 1368 with respect to alternative compliance for multi-jurisdictional utilities. In addition, clarification to the definition of "capacity factor" has been requested by some parties for compliance purposes. The final report does not provide specific recommendations on these issues.

Finally, there is disagreement among parties over whether offsets or other compliance options (such as "portfolio averaging") are appropriate for an interim EPS. We address these and other compliance-related issues below.

5.1. Compliance Process for PG&E, SDG&E and SCE

Parties commenting on this issue recognize that the Commission requires the largest electrical corporations (i.e., SCE, PG&E and SDG&E) to file long-term procurement plans for review and approval by the Commission pursuant to § 454.5, and also requires SCE, PG&E and SDG&E to seek Commission pre-approval before they can enter into procurement contracts of five years or longer.[188] There is consensus among the parties that the same procedural vehicles used by these LSEs to seek Commission pre-approval of their long-term procurement contracts should be used to seek pre-approval of covered

[188] This section of the Public Utilities Code was added by AB 57 (Stats 2002, ch. 835), and applies to all electrical corporations. As provided for under § 454.5(i), electrical corporations serving less than 500,000 customers are exempt from this procurement plan review and approval process.

commitments under the EPS rule we establish today. We agree, and outline those procedures below.

SCE, PG&E and SDG&E currently bring all power purchase contracts with terms of five years or longer before the Commission for review and pre-approval by filing either an advice letter (for RPS-contracts) or an application (for non-RPS contracts). For all RPS contracts, we use the advice letter process established in our RPS proceeding to pre-approve those procurements.[189] Each advice letter is reviewed by Energy Division, and a Commission resolution addressing the RPS contract is prepared for Commission approval. Under existing procurement rules adopted in D.04-12-048, PG&E, SCE and SDG&E file applications requesting Commission review and pre-approval of all non-RPS contracts with a term of five years or more. The Commission issues a decision addressing the applications.

We will use these existing procedural vehicles for reviewing and pre-approving PG&E, SCE and SDG&E's covered procurements with respect to EPS compliance. As discussed in Section 4.2, "covered procurements" includes new and renewal contracts of five years or greater with baseload generation, LSE new investment in baseload generation (new construction) as well as major alterations to baseload facilities. For PG&E, SCE and SDG&E, each of the various types of covered procurements subject to the EPS will be reviewed and pre-approved through the advice letter process (for RPS resources) or application process (for non-RPS resources) described above.

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[189] See D.03-06-071, p. 39, issued in R.04-04-026, the predecessor to our current RPS proceeding, R.06-05-027.

More specifically, for covered procurements with RPS-eligible baseload generation, these utilities shall submit documentation to demonstrate compliance with the EPS through RPS advice letter filings. These advice letters shall be served on the service list in our RPS Rulemaking, R.06-05-027, or its successor proceeding. Should an application process be used for any particular RPS contract, or should the advice letter process set forth in D.03-06-071 be changed in whole or in part to an application process in the future, that process will automatically apply to the EPS compliance filings required of SCE, PG&E and SDG&E for RPS resources.[190]

For all non-RPS covered procurements, PG&E, SCE and SDG&E shall submit documentation to demonstrate compliance with the EPS through the non-RPS application process established by our procurement rules. This includes any request for a Commission finding of EPS compliance for covered procurements that employ geological formation injection for CO_2 sequestration. These applications shall be served on the service list in our Long-Term Procurement Rulemaking, R.06-02-013, or its successor proceeding. The Commission's determination on these matters will address the compliance of the covered procurements with our EPS rules.

As discussed in this decision, any request for a reliability exemption or an exemption based on "extraordinary circumstances, catastrophic events, or threat of significant financial harm" will require Commission pre-approval. We direct SCE, PG&E and SDG&E to file such requests by application with service on the

[190] However, if the RPS advice letter process set forth in D.03-06-071 is modified to include procedures whereby these advice letters may be "deemed approved," such procedures shall not apply for the purpose of establishing EPS compliance.

service list in both R.06-02-013 and this proceeding, or their successor proceedings. Any request for an extraordinary circumstances modification shall be filed as a petition for modification of this decision.

In addition, we require all LSEs to disclose in their compliance submittals any multiple contracts of less than five years with the same supplier, resource or facility. (See Section 5.5 below.) We direct SCE, SDG&E and PG&E to disclose this information in their Quarterly Procurement Plan Compliance Reports[191] that demonstrate compliance with all Commission procurement rules.

5.2. Compliance Process for Small Electrical Corporations, Electric Service Providers and Community Choice Aggregators

Currently, the Commission does not require electric service providers, community choice aggregators or the "small electrical corporations" (i.e., those other than PG&E, SCE and SDG&E) to submit procurement plans or apply for pre-approval of long-term procurement contracts. AReM, Constellation, Plumas-Sierra and others argue that such pre-approval requirements should not be established for these entities for the purpose of demonstrating EPS compliance. Instead, they recommend that electric service providers, community choice aggregators and the small electrical corporations make a more simplified after-the-fact compliance showing. In particular, AReM recommends using the existing resource adequacy compliance submittal for this purpose, which SCE, PG&E, SDG&E, electric service providers and community choice aggregators are

[191] Pursuant to D.02-10-062.

required to file annually as an Advice Letter.[192] PG&E, SMUD, CMUA, Northern California Power Agency and the Southern California Public Power Authority support this approach in their comments.

Specifically, AReM envisions a process whereby in most cases, the electric service provider would simply certify that it had not entered into any financial commitments during the previous year that are subject to the EPS. If it had entered into such commitments, the electric service provider would provide documentation to show that the commitment was in compliance with the EPS. Constellation also suggests that the electric service provider could be subject to an independent third-party audit if the Commission has any doubt that the electric service providers are forthcoming in their demonstrations.

NRDC/TURN/UCS and WRA object to relying on procedures that would allow for after-the-fact compliance submittals, as recommended by AReM and others. They argue that this approach is not consistent with SB 1368 or with the concept of an upfront gateway standard. In their view, allowing electric service providers or other LSEs to show compliance after-the-fact would not offer the same protection to its customers and would open a significant loophole to compliance if in the end an electric service provider did enter into a long-term financial commitment that violated the performance standard. In their view the

[192] Currently, the smaller electrical corporations (e.g., Plumas-Sierra) and multi-jurisdictional utilities (Sierra Pacific Power Company (Sierra Pacific) and PacifiCorp) are not required to demonstrate resource adequacy compliance at this Commission. The resource adequacy rules for these entities are being developed in Phase 2 of R.05-12-013. See *Assigned Commissioner's Ruling and Scoping Memo* in R.05-12-013, March 1, 2006, p. 4.

standard must be enforced on an upfront basis for all LSEs before any long-term commitments are made.[193]

We read § 8341(a) to mean that all LSEs must comply with the statute if they enter into any long-term financial commitment involving baseload generation, irrespective of whether (or how) this Commission reviews and approves such commitments. Subsections (1)-(6) of § 8341(b) describe a variety of things that the Commission shall or may do related to the implementation of the EPS program, none of which imposes a requirement on the Commission that it must pre-approve all long-term commitments made by the LSEs. Had it intended to make this requirement, the Legislature could have directed, for example, that no electrical corporation shall enter into a long-term financial commitment unless it is pre-approved by the Commission.

It did not do so. Instead, the language of subsection (1) states that "the Commission shall not approve a long-term financial commitment by an electrical corporation unless any baseload generation supplied under the long-term financial commitment complies with the greenhouse gases emission performance standard established by the commission..." We read this to mean that if the Commission does approve such commitments in the first place, which is the case for the large investor-owned utilities in our procurement proceeding, we must make a determination that the commitment complies with the EPS.[194] Similarly,

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[193] *Opening Comments/Legal Brief on Final Workshop Report and Staff Recommendations Regarding the GHG Performance Standard of NRDC/TURN/UCS/WRA*, October 18, 2006, pp. 15-16, and *Reply Comments on the Draft Workshop Report Regarding the GHG Performance Standard of NRDC/TURN/UCS/WRA*, September 15, 2006, p. 5.

[194] We may make that determination on a case-by-case basis requiring that the LSE present a showing for each individual commitment, or we may make a one-time, up

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subsection (2) does not require that we review long-term financial commitments that are proposed to be entered into by an electric service provider or community choice aggregator, but only states that we "may" do so. Therefore, in adopting rules and procedures to ensure compliance with the EPS, pursuant to § 8341(b)(3), we have the flexibility under the statute to consider a range of procedural vehicles for use by those LSEs for whom we do not currently have a procurement pre-approval process in place.

With certain exceptions, we provide for "after-the-fact" EPS compliance submittals for electric service providers, community choice aggregators and small electrical corporations.[195] We concur with AReM, Constellation and others that EPS compliance procedures that do not require Commission pre-approval are appropriate for those LSEs who are not required to submit procurement plans or procurement contracts for pre-approval under current Commission procedures. We believe that the documentation and other requirements adopted today provide reasonable safeguards against the risks to ratepayers of potential non-compliance by an LSE that files an after-the-fact compliance showing. At the same time, this approach avoids creating new pre-approval requirements and associated administrative complexity for the Commission's regulation of the procurement practices of these entities. Moreover, we note that we have already established procurement-related compliance procedures for electric service

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front determination for specific resources or technologies, as we have today for certain renewable resource technologies.

[195] The multi-jurisdictional utilities with less than 75, 000 California retail customers that receive Commission approval of alternate compliance under § 8341(d)(9) will not need to demonstrate EPS compliance at the Commission, and therefore would not be required to file an Attestation Letter. See Section 5.3 below.

providers and community choice aggregators that are similar to what AReM and others now propose for demonstrating EPS compliance. We think that this approach is reasonable for the interim EPS, with the following qualifications.

First, we do not adopt the resource adequacy filing as referred to by AReM and others as the procedural vehicle for these submittals. This filing is a compliance submittal related to a one-year ahead capacity obligation, rather than a multi-year procurement obligation or rule. The Commission does not review any contracts in the resource adequacy filing process. Compliance is demonstrated through a template and through the obligation of the capacity resources to "show up" through real time at the California Independent System Operator. Therefore, we do not believe it is appropriate to include the EPS-compliance showing in this particular filing. Instead, electric service providers, community choice aggregators and electrical corporations other than SCE, PG&E and SDG&E will be required to file an annual Attestation Letter, due by February 15 of each year, attesting to the Commission that the financial commitments it has entered into during the prior calendar year are in compliance with the EPS.

Second, the Attestation Letter shall comply with all documentation requirements described in Section 5.5, and contain a certification, including the name and contact information for the LSE officer(s) certifying the following under penalty of perjury:

> "(1) I have reviewed, or have caused to be reviewed, this compliance submittal.
>
> "(2) Based on my knowledge, information, or belief, this compliance submittal does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements true.

> "(3) Based on my knowledge, information, or belief, this compliance submittal contains all of the information required to be provided by Commission orders, rules, and regulations."

Third, the Attestation Letter shall be filed as an advice letter, subject to the Commission procedures governing advice letter filings, which include opportunity for protests and responses.[196] However, no Attestation Letter shall be "deemed approved" under those procedures.

Energy Division shall review each Attestation Letter and approve it if it contains all elements required by the EPS documentation requirement, includes a certification by the responsible corporate officers, and if the facts state in the Attestation Letter show compliance with the EPS. Energy Division approval of the advice letter means that the Attestation Letter is in compliance with these rules, and that any procurement *as reported in the Attestation Letter* complies with the requirements of the EPS program. Energy Division approval does not mean that LSE procurements that are unreported or inaccurately reported comply with the EPS. LSEs shall be subject to penalties if the attestation letters are found, at a later date, to be incomplete, misleading or incorrect.

In its Opening Comments on the Proposed Decision, the City of San Francisco objects to our discussion of penalties, here and in other sections of the

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[196] See D.05-01-032, Appendix: Advice Letter Filing, Service, Suspension and Disposition. We are in the process of updating these procedures in R.98-07-038, and as indicated in Section 5.1 above, may also modify the advice letter process set forth in D.03-06-071 in the future. We recognize that some clarifications or modifications to procedures for the annual Attestation Letters and other advice letter compliance submittals adopted today may need to be made after the effective date of this decision in order to reconcile them with updated Commission procedures for advice letters in R.98-07-038 or R.06-05-027, or their successor proceedings. We delegate to the Assigned

Footnote continued on next page

decision. It argues that it is inappropriate to address the imposition of penalties on LSEs that are governmental entities, until "more detail is provided regarding the authority and process for the imposition of penalties."[197] We disagree. The specific authority and process for imposing any penalties can be addressed if and when any violations occur. The point of our brief discussion of penalties is to inform all LSEs that we will take violations of the EPS and our reporting requirements seriously, and thereby help ensure that violations do not occur.

In addition, an electric service provider, community choice aggregator or small electrical corporation may, at its discretion, submit an advice letter during the year requesting pre-approval of a new financial commitment as EPS compliant when there is uncertainty about whether the financial commitment will comply with our EPS rules. All advice letter filings, as well as responses or protests, shall be served on the service list in this proceeding or its successor proceeding.[198] We caution electric service providers, community choice aggregators and small electrical corporations not to burden this process with requests for pre-approval of financial commitments that are clearly exempt from having to show EPS compliance, such as a single contract for a term of less than five years.

As discussed elsewhere in this decision, all LSEs are required to file (1) an application requesting Commission pre-approval for a reliability exemptions, (2) a petition for modification of this decision where the request is based on

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Commissioner the authority to make such clarifications or modifications by ruling or other manner, in consultation with the assigned ALJ and Energy Division.

[197] *Opening Comments of the City of San Francisco on the Proposed Decision*, January 2, 2007, p. 10.

"extraordinary circumstances, catastrophic events, or threat of significant financial harm" or (3) an application for covered procurements that employ geological formation injection for CO_2 sequestration. Accordingly, the advice letter process described above will not be applicable to these types of requests. Instead, small electric corporations, electric service providers and community choice aggregators are required to file such requests by application or petition for modification, and serve them on the service list in this proceeding, or its successor proceeding.

5.3. Alternative Compliance Provisions for Multi-Jurisdictional Electrical Corporations

SB 1368, permits the Commission to consider a showing of "alternative compliance" by multi-jurisdictional electrical corporations that serve 75,000 or fewer retail end-use customers in California. Specifically, § 8341(d)(9) states that these LSEs:

> "...may file with the commission a proposal for alternative compliance with this section, which the commission may accept upon a showing by the electrical corporation of both of the following:
>
> "(A) A majority of the electrical corporation's retail end-use customers for electric service are located outside of California.
>
> "(B) The emissions of greenhouse gases to generate electricity for the retail end-use customers of the electrical corporation are subject to a review by the utility regulatory commission of at least one other state in which the electrical corporation provides regulated retail electric service."

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[198] However, no such advice letter shall be "deemed approved."

Upon Commission approval of a showing of alternative compliance, under § 8341(d)(9), a utility shall not be required to demonstrate compliance at this Commission for their California operations pursuant to the procedures we adopt in Section 5.2 above.

The two multi-jurisdictional utilities subject to SB 1368, Sierra Pacific and PacifiCorp, both state in their comments that they meet § 8341(d)(9)'s qualification requirements for alternative compliance with the EPS. In the Proposed Decision, we agreed with PacifiCorp's proposal for how to determine whether a multi-jurisdictional electrical corporation's GHG emissions are "subject to a review" by the public utilities commission of another state, part B of the statutory alternative compliance requirements.[199] Under this test, an electrical corporation would satisfy part B of SB 1368's alternative compliance provision when any of the following occur 1) a state jurisdiction requires the utility to review and report on the potential impacts of different carbon policies within its Integrated Resource Planning process; or 2) when it requires the utility to disclose its greenhouse gas emissions or expected change in overall emissions as a result of changes to its portfolio, including new capacity additions; or 3) when a state jurisdiction adopts rules specifically regulating emissions of greenhouse gases from electricity generating facilities.[200] PacifiCorp further

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[199] We see no reason to put this policy decision off for another day as suggested by NRDC. (*Opening Comments of NRDC on Final Staff Workshop Report.* October 18, 2006, p. 8.) We agree with Sierra Pacific and PacifiCorp that we should now determine what constitutes a showing of alternative compliance, so as to facilitate their preparation of the resource plans that they will be presenting to several public utilities commissions.

[200] *Opening Comments of PacifiCorp on Draft Staff Workshop Report*, September 8, 2006, p. 3.

states that "four of our six state commissions require PacifiCorp to consider greenhouse gas emissions in electricity resource planning."[201]

In summary, a multi-jurisdictional electrical corporation can demonstrate alternative compliance if it (1) serves fewer than 75,000 retail customers within California, (2) a majority of its retail customers are located outside of California, and (3) it is subject to any one of the three kinds of carbon emissions related regulation described above.

In the Proposed Decision, we concluded that until alternative compliance was approved by the Commission each multi-jurisdictional should file its alternative compliance proposal as an application with service on the service list in this proceeding, or its successor proceeding. We further concluded that until the application was approved by the Commission, all multi-jurisdictional utilities should be required to submit annual Advice Letters demonstrating compliance with the EPS pursuant to the procedures discussed in Section 5.2 above. We further required that the multi-jurisdictional utility's compliance filings should describe the method used to identify and allocate its long-term financial commitments to California retail customer load.

Upon further review, however, we conclude that both Sierra Pacific and PacifiCorp meet the alternative compliance requirements described in the Proposed Decision. Both multi-jurisdictional utilities are still required to file annual advice letters on February 1 of each year, starting in 2008, attesting that they still meet the alternative compliance requirements.

Sierra Pacific provides electricity to 45,000 customers within the state of California with the vast majority of its load residing in Nevada.[202] Nevada

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[201] *Reply Comments of PacifiCorp on Final Staff Workshop Report*, October 27, 2006, p. 5.

Administrative Code §§ 704.2783 and 704.2785 require Sierra Pacific to disclose to its customers twice each year the average emissions of carbon dioxide, sulfur dioxide, and carbon monoxide as measure in lbs/MWh produced by internal generation and purchased power.[203] Since §§ 704.2783 and 704.2785 require that Sierra Pacific "disclose its greenhouse gas emissions" it satisfies option 2, thereby establishing that Sierra Pacific is "subject to a review", and satisfying part B of SB 1368's alternative compliance requirements.[204]

Similarly, a minority of PacifiCorp's customers, 2% or 43,777, are located in California.[205] PacifiCorp further states that "four of our six state commissions require PacifiCorp to consider greenhouse gas emissions in electricity resource planning."[206] In the table provided on page 8 of its October 18th comments PacifiCorp indicates that it is subject to some kind of carbon emissions regulations in Oregon, Utah, and Washington, each of which hosts a larger percentage of PacifiCorp's load than California.

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[202] See *Opening Comments of Sierra Pacific Power Company on Final Staff Workshop Report,* October 18, 2006, pp. 3-4.

[203] *Id.*

[204] Moreover, Sierra Pacific stated in its comments that its 2007 Integrated Resource Plan, which will be filed with the Nevada Public Utilities Commission, is subject to review pursuant to Nevada Administrative Code § 704.9359 which requires Sierra to review and quantify environmental costs from air emissions.[204] (Sierra Pacific *Opening Comments to Staff Final Workshop Report*, p. 4). This code section may satisfy part B's "review" standard independent of Nevada's emissions disclosure requirement.

[205] *Opening Comments of PacifiCorp on Final Staff Workshop Report,* October 18, 2006, p. 6.

[206] *Reply Comments of PacifiCorp on Final Staff Workshop Report,* October 27, 2006, p. 5.

Recently the Oregon Public Utility Commission issued Order 07-002[207] which, in conjunction with Order 93-695, requires PacifiCorp to include in their Integrated Resource Planning filings the potential regulatory compliance costs for $C0_2$ Nitrous Oxides, Sulfur Oxides, and mercury emissions. Under option 1 of our "subject to a review" test, another state's regulation or statute which "requires the utility to review and report on the potential impacts of different carbon policies within its Integrated Resource Planning process" qualifies as "review" for the purposes of SB 1368's alternative compliance provision. Since 07-002 requires that PacifiCorp report the expected regulatory compliance costs associated with an array of GHGs, including $C0_2$, within its Integrated Resource Planning process, it satisfies Option 1 of our test to determine whether or not a multi-jurisdictional utility is "subject to a review" in another jurisdiction.

Both PacifiCorp and Sierra Pacific, therefore, have made a satisfactory showing that they satisfy SB 1368's alternative compliance requirements.

5.4. Portfolio Averaging, Offsets and Other Proposed Compliance Options

CEED, LS Power and SCE argue that the interim EPS should include an offsets program, whereby the LSE would have the option to offset emissions from a high-emitting baseload resource with GHG emissions reductions secured elsewhere to bring it into EPS compliance. For this purpose, these parties advocate allowing offsets secured from industries other than just the electric

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[207] Pursuant to Rule 13.9 of the California Public Utilities Commission Rules of Practice and Procedure, we may enter other state's agency's official orders into the record by official notice. We hereby take notice of Oregon PUC Order 07-002 (*Investigation Into Integrated Resource Planning (Disposition: Guidelines Adopted; Rulemaking and Investigation Opened)*, January 8, 2007).

generating sector and without geographic restrictions. They provide no specifics on how such an offsets program could be established and enforceable by the statutory deadline, but contend that allowing them would provide flexibility in meeting the goals of the EPS, spur broader innovation, and control costs.

For similar reasons, CEED advocates "portfolio averaging," although it is not clear from CEED's submittal what exactly that means in the context of an EPS applied on a commitment-by-commitment basis. Presumably, the Commission would look at a "portfolio" of long-term commitments made by the LSE over some period of time, and then assess EPS compliance with respect to the average emissions rate of that portfolio.

In its draft and final report, staff recommends that the Commission not include these types of compliance options because they would require significant upfront analysis and ongoing reporting and monitoring requirements, resulting in delays in both the implementation and enforcement of an interim EPS. For this and other reasons, Calpine, IEP, NRDC, TURN, UCS and WRA do not support the use of offsets or portfolio averaging to comply with the EPS. In their view, such compliance options do not fit within the concept of an interim EPS and would serve to defeat its purpose.

We agree with staff and these parties that one reason to reject the compliance options proposed by CEED and others is that they cannot be designed and implemented within the timeframe contemplated for an interim EPS, particularly in light of the statutory requirement that an enforceable EPS be put in place no later than February 1, 2007. However, there is another, more fundamental reason to reject them: Allowing the LSE to use portfolio averaging or offsets to comply with the EPS would compromise the very purpose of establishing a GHG emissions-based standard in the first place.

As discussed throughout this decision, the interim EPS is intended to be a facility-based minimum performance standard governing long-term commitments made by an LSE to baseload generation facilities. This reflects a fundamentally different purpose, serving different policy objectives, than programs to reduce GHG emissions through a portfolio-wide cap, cap-and-trade programs or programs that permit LSE's to use offsets to meet an emissions cap or performance standard. The purpose of these programs is to provide varying degrees of compliance flexibility when the primary policy goal is to reduce the overall level of emissions generated through procurement activities.

In particular, portfolio-averaging permits an LSE to meet an emissions limit (or "cap") with a variety of short-term and long-term procurement combinations. For example, the LSE can procure electricity (build or purchase) on a long-term basis from a very high-emitting generating facility as long as it has other resources in its procurement portfolio that lower the average enough to meet the emissions cap from year-to-year. In other words, as long as the emissions associated with the LSE's overall procurement portfolio do not exceed the total number of allowances (permitted level of emissions) allocated to it, the LSE will be in compliance with the program.[208] Under a "cap-and-trade" program, the allowances allocated to the various LSEs subject to the cap can be traded. Thus, for example, the emissions of an LSE's procurement portfolio may exceed the number of allocated emission allowances if the LSE can purchase

[208] An "allowance" refers to a permit provided to the LSE within the scope of the emissions cap to emit one unit of emissions (e.g., tons of CO_2). The total number of available allowances reflect the total amount of permissible emissions, and usually decline over time. Allowances are allocated administratively or by auction to the entities subject to the cap.

additional allowances from LSEs that do not need the number of allowances that they currently hold.

An offset program permits the LSE to make a reduction in emissions outside the scope of the emissions cap, which in turn allows an increase in emission levels associated with the LSE's procurement portfolio. The LSE can purchase offsets from third parties making investments to reduce emissions elsewhere (for example, investments in reforestation or in low-emissions vehicles or in the electric sector of other countries), or make those investments itself. This permits the LSE to exceed its allocated GHG emissions allowances. Under any of these compliance approaches to a GHG emissions cap, the LSE may enter into long-term financial commitments with high-emitting powerplants as long as it meets the level of the emissions cap for its portfolio as a whole, or acquires allowances and/or offsets to increase the permissible level of portfolio emissions.

In contrast, the interim EPS is aimed at ensuring that an LSE *does not enter into long-term financial commitments with high-emitting baseload resources in the first place.* This is because the primary objectives of the interim EPS is to ensure that there is no "backsliding" as California transitions to a statewide GHG emissions cap. This objective cannot be accomplished if LSEs are permitted to comply with the standard by diluting the emissions from non-compliant powerplants through portfolio averaging or increasing the permissible level of emissions for these powerplants (e.g., through offsets). These options would only disguise the types of problems that the EPS is designed to avoid, e.g., the high costs of future plant retrofits and reliability disruptions as it becomes increasingly difficult for these

high-emitting facilities to comply with GHG emission regulations, such as the AB 32 declining cap on statewide GHG emissions.[209]

For these reasons, we do not adopt offsets or portfolio averaging in the context of today's adopted interim EPS. In the context of a load-based cap, however, we fully intend to evaluate a broad range of flexible compliance options as we proceed to implement the Procurement Incentive Framework during Phase 2 of this proceeding. Pursuant to AB 32, flexible compliance options will also be evaluated as California proceeds to implement the emissions limits required under that new law on a statewide basis.[210] As we stated in D.06-02-032, we will focus our efforts during Phase 2 on ensuring that the compliance options that we do permit under the Procurement Incentive Framework are credible, verifiable and administratively feasible. During Phase 2, we intend to carefully explore the pros and cons of alternate proposals for offsets, trading, banking and borrowing and other compliance options before making our final determinations. Throughout the process, we will closely coordinate with CARB, the Governor's Climate Action Team as well as other state, regional or federal agencies that are exploring design options for cap-and-trade programs.[211]

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[209] AB 32, § 38562(c).

[210] AB 32, § 38561, § 38570.

[211] D.06-02-032, p. 44.

5.5. Documentation Requirements and Contract Linkage Issues

5.5.1. Documentation Requirements

In their compliance submittals, all LSEs[212] should include a listing of the new long-term financial commitments of five years or longer they plan to enter into (SCE, PG&E and SDG&E) or have entered into during the prior year (electric service providers, community choice aggregators, small electrical corporations) with documentation to demonstrate:

(a) That the commitments were not "covered procurements" under the interim EPS rule and/or

(b) For those that represent covered procurements, documentation demonstrating that such procurements are EPS-compliant, including any contracts with a term of five years or longer that include provisions for substitute energy purchases.

(c) For any requested reliability-based exemptions that have been pre-approved by the Commission, a reference to the application and Commission decision number.

Consistent with our discussion in today's decision that "linked" contracts are to be treated as a single contract for purposes of EPS compliance, this listing of new long-term financial commitments of five years or longer must include "linked" contracts whose combined term is five years or longer. Further, disclosure of LSE investments in retained generation, including "deemed-compliant" CCGTs, is also necessary to monitor compliance with the interim EPS

[212] With the exception of Sierra Pacific and PacifiCorp, both of which have made a satisfactory showing that they meet SB 1368's alternative compliance requirements. (See Section 5.3.) Their annual advice letters are not required to include the information contained in this section but rather, each should attest that the utility still meets the alternative compliance requirements described herein.

rules. Therefore, we require all LSEs to disclose the investment amount and type of alteration to retained generation, by generation facility and unit. As discussed above, electric service providers, community choice aggregators and small electrical corporations will need to provide this information in their annual Attestation Letter. SCE, SDG&E and PG&E are required to disclose this information in their Quarterly Procurement Plan Compliance Reports[213] that demonstrate compliance with all Commission procurement rules. In addition, the burden is on each LSE to provide sufficient documentation in compliance submittals to demonstrate that the limits to substitute energy purchases with unspecified resources described in Section 4.12 are reflected in any contracts with a term of five years or longer that include substitute energy provisions.

As discussed in this decision, we permit case-by-case review of reliability exemptions and requests for modification based on extraordinary circumstances, catastrophic events, or threat of significant financial harm" due to circumstances unforeseen by SB 1368 and this decision, with the caveat that any consideration of such exemptions comes with a heavy burden of proof on the LSE. Any LSE requesting review and pre-approval of a reliability-based exemption from the EPS rule must provide documentation demonstrating that such long-term procurements are necessary to ensure system reliability. We caution all LSEs that they should not asked to be excused from the requirements of this decision for any other reason unless they can clearly demonstrate that: (1) they are facing extraordinary circumstances, catastrophic events or threat of significant financial harm not contemplated by SB 1368 and this decision, and (2) an exemption from some requirement of this decision is necessary to significantly mitigate or

[213] Pursuant to D.02-10-062.

eliminate the challenges posed by these circumstances. These requests must be pre-approved by the Commission and shall be made by application in the case of a reliability exemption request, or petition for modification in the case of an "extraordinary circumstances" request, as discussed in Section 4.8.5.

We also require LSEs to file an application requesting a Commission finding of EPS compliance for any covered procurement that employs geological formation injection for CO_2 sequestration. As part of this filing, the LSE shall provide documentation demonstrating that the geological formation injection project has a reasonable and technically feasible plan that will result in a permanent sequestration of CO_2 once the project is operational.

Several parties have requested further guidance on the documentation required to determine whether a long-term financial commitment represents a commitment to baseload generation and if so, the associated emissions rate to use in evaluating EPS compliance.

We believe that the guidance provided in SB 1368 is instructive on this issue. Specifically, in determining whether a long-term financial commitment is for baseload generation, § 8341(b)(4) directs that we "consider the design of the powerplant and the intended use of the powerplant." This section goes on to enumerate several sources of information that are relevant for this purpose (e.g., the electricity purchase contract, any certification received from the CEC, any other permit or certificate necessary for the operation of the powerplant, any procurement approval decision). It also states that we may base our determination on "any other matter" that we find to be "relevant under the circumstances."

Accordingly, in their compliance filings, LSEs are advised to present documentation regarding the design and intended use of the powerplant(s)

underlying their new long-term financial commitments utilizing the sources of information listed in § 8341(b)(4), as well as any other sources of documentation that they believe will be relevant to this determination. The key concept here is that the documentation should relate to establishing the design and intended use of the powerplant. As discussed in Section 5.6 below, documentation of the annualized plant capacity factor for the powerplant should include historical annual averages in order to help determine whether the plant is "designed and intended" to be used for baseload generation.

We note that PG&E proposes demonstrating compliance with the EPS thorough "documentation of the facility's full load heat rate and expected capacity factor"[214] However as NRDC and others observe, the full load heat rate is the heat rate of a plant at full output and is not representative of the actual operations of a plant. Full load heat rates are lower than heat rates during actual plant operations, and therefore underestimate the heat rates and corresponding emissions of plants that are operating as "designed and intended."[215] Rather than assume full load heat rates, as PG&E proposes, LSEs should provide documentation of capacity factors, heat rates and corresponding emissions rates that reflect the actual, expected operations of the plant.

For similar reasons, we reject the recommendation of PG&E and Northern California Power Agency that we *require* all LSEs to use the International Organization for Standardization measurement standards to document the capacity factors, heat rates and corresponding emission rates in demonstrating

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[214] *Comments of PG&E on Draft Workshop Report*, September 8, 2006, p. 4.

[215] This is because as the plant output decreases, the corresponding heat rate (Btu/kWh) increases, and emissions are proportional to heat rate for the same fuel type.

EPS compliance. Our understanding of these measurement standards is that they normalize based on the temperature, atmospheric pressure and relative humidity typical of those parts of the globe where the majority of the population lives, i.e., at the seacoasts.[216] As a result, these standards may not be appropriate for use by all LSEs in documenting EPS compliance, particularly for those powerplants located in high temperature or high altitude regions.

5.5.2. Linkage Issues

In their opening comments on the Proposed Decision, both SCE and Constellation urge us to more clearly explain what we mean by "linked" contracts, that although individually for a term of less than five years, together have a term of five years or more, and therefore may be subject to the EPS. We agree that this concept needs to be spelled out in detail now, so that the LSEs can comply with the EPS. SCE makes several suggestions as to how to determine whether two, or more, contracts are "linked"; the second of these of these suggestions contains a number of useful elements. SCE suggests that contracts be considered "linked" in either of the following situations: "(1) the contracts specify the same generating unit as the primary source and the gap in contract execution dates is six months or less; or (2) the contracts do not specify the generation source, are with the same supplier, specify the same delivery point, and are executed within 24 hours."[217]

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[216] Namely, 15 degrees Celsius (59 degrees Fahrenheit), 1 atmosphere of pressure (sea level, or 14.7 psi or 101.3 kPa), and 60 percent relative humidity.

[217] *Opening Comments of SCE on the Proposed Decision*, January 2, 2007, p. 9.

The purpose of requiring "linked" contacts—for baseload generation--with a combined term of five years or more to comply with the EPS is to prevent LSEs from circumventing the EPS by splitting up a single commitment into multiple contracts (or using a contractual option in place of a binding contract). With this goal in mind, we consider SCE's suggestion.

First we consider SCE's proposal that for contracts with an unspecified generation source the contracts must be executed within 24 hours of each other to be considered linked. This proposal would make it too easy to circumvent the EPS. Under this proposal an LSE could negotiate two contracts with the same seller (counter-party), one for a term of four years, and the other for a term of three years beginning on the expiration of the first contract, and avoid application of the EPS simply by delaying the signing of one contract by two days. The underlying reality would be that there was a single deal with one counter-party to provide electricity for a term of seven years. Pursuant to SB 1368, this deal should be required to meet the EPS if it is for baseload generation.

Furthermore, we do not think that the date of execution of the contracts, standing alone, should be the determining factor in deciding whether two contracts are sufficiently related to be considered one for purposes of applying the EPS. Turning again to the example in the above paragraph, we do not think that the two contracts described there should be considered separate, regardless of how long the parties wait to execute the second one, if they were negotiated at (or about) the same time. In that situation, the underlying reality would still be that there was a single deal with one counter-party to provide electricity for a term of seven years. Thus, we conclude that we should expand upon SCE's concept that two contracts should be considered linked if they are both *executed*

within a specified window of time. Instead two contracts should be considered linked if both of them are *negotiated or* executed within a specified time-window. (For more than two contracts to be "linked" all of them would have to be negotiated or executed within the same window of time.)

While SCE proposed a 24-hour window for contracts with unspecified generation sources, it proposed a six-month window for contracts with specified generation sources. However, its six-month proposal would take into consideration only the dates of contract execution. As explained above, we must reject SCE's proposal for a 24-hour window and expand the window concept to consider whether negotiation of the two contracts occurred during the same window period. This expansion will cover contracts whose execution dates may be farther apart than the window-period. Accordingly, we conclude that a three-month-window period should be sufficient for contracts with specified generation sources, and that the same window period should apply to contracts with unspecified generation sources. This three-month window period represents a compromise between the one-day and six-month periods suggested by Edison, and is consistent with the use three-month periods used elsewhere in our procurement rules.

We now turn to consider one other detail of SCE's proposal that we decline to adopt. SCE proposes that in order for two "unspecified" contracts to be linked they must "specify the same delivery point." Because it is possible for power from the same plant (or group of plants) to be delivered to the LSE at different points, we conclude that such a requirement would make it too easy to evade the EPS by splitting up a single deal into two contracts with different delivery points. We will also modify SCE's proposal to substitute the word

"powerplant" for the words "generating unit" to be consistent with the terminology we use throughout these EPS rules.

SCE's primary proposal for determining whether two contracts are "linked" is quite different from the proposal we have just been discussing. SCE suggests that if "two contracts are 'independent' of each other, the Commission should not consider them to be 'linked.' Two contracts are 'independent' of each other if selection of one does not require selection of the other. That is, in order to be selected, each contract in a series of multiple contracts must 'win on the merits.'" However, this proposal does not contain sufficiently clear guidelines to enable an LSE to determine if two contracts will be considered linked. Accordingly, we decline to adopt it.

However, the concept of "winning on the merits" does call to mind the utilities' RFO (Requests for Offers) procedures. And we think that one further modification to SCE's alternative proposal for dealing with "linkage" should be made to reflect those RFO procedures. Our concern has been that a single deal not be cut up into several contracts in order to avoid compliance with the EPS. The RFO procedures structure the utilities negotiation of contracts. Given that structure, we conclude that, under certain circumstances, even if two contracts are signed within three months of each other they should not be considered part of the same deal. More specifically, two contracts should not be considered linked if they are entered into as a result of separate RFOs and the contract from the earlier RFO is executed before the later RFO has received bids. In that situation it is clear that each contract was negotiated separately, and that they should therefore be treated as two separate deals. Conversely, if a bid on the second RFO is submitted before the first contract has been executed, it is possible that the two contracts might have been negotiated at the same time, and

therefore the linkage rule should apply. Under some RFOs indicative bids are received first, followed by final bids; in other RFOs there are only final bids. In order to accommodate this variation we will require that the contract from the first RFO be executed before the LSE receives any bids (whether indicative or final).

LSEs might also attempt to circumvent the EPS by including an option for extension within a contract, rather than entering into a binding contract for a term of five years or more. For example, an LSE that wanted to enter into a seven-year contract with a non-compliant generator, might instead enter into a contract that required the LSE to purchase electricity for four years and also included an option to extend the contract for three more years. This is essentially a deal to purchase electricity for more than five years, and ought to be subject to the EPS screen. Accordingly, both binding contracts and contractual options should be analyzed to see whether they are "linked" and if so, whether their "term" is for five years or more.

Putting all these concepts together and in a somewhat different format, we come up with the following rule:

For the purpose of determining the "term" of a contract under these EPS rules, two or more contracts, including contractual options, are treated as one ("linked"), where:

A. (1) They specify the same powerplant as the primary delivery source or, (2) for an unspecified source, they are with the same counter-party;

and

B. They are negotiated or executed within any three consecutive-month period, except if entered into as a result of separate RFOs and the contract from the earlier RFO is executed before the later RFO has received any bids (either indicative or final).

Because parties expressed concern that they know, in advance, how the linkage rule will be applied, we will provide a number of examples, along with some explanation. For our first example, let us consider an LSE that enters into a contract for electricity from a specified powerplant for a two-month term, and repeatedly enters into additional contracts for electricity generated by the same powerplant, each with a term of two months commencing on the expiration of the prior contract. Although some of these contracts will be considered "linked," it is highly unlikely that a group of linked contracts will ever come close to the five-year term required for the EPS to be applicable. Two or more contracts are linked only where they are negotiated or executed within the same three-month period. Thus, in order for a group of linked contracts to have a five-year term, the contracts that are executed or negotiated within a single three-month period must have a final delivery date that is five or more years after the initial delivery date.[218] In this first example (successive two-month contracts), it is likely that several of these contracts will be negotiated or executed within the same three-month period. However, it is highly unlikely that 30 of these successive contracts will have been negotiated or executed all within three months of each other, and unless they are, the total term of any group of linked contracts will not equal five years. In that case, the EPS will not apply.

For our second example, let us consider the situation where an LSE enters into a contract for 20% of the power from powerplant X, and the contract allows the seller to substitute power from powerplant Y, if X is unavailable. This contract is executed on 4/2/07, and has a term of three years, with delivery

[218] See section 4.2.4 above, explaining how to determine the "term" of a contract.

commencing on 1/1/09. On 5/15/07, the same LSE executes a contract for 15% of the power from powerplant Z, with substitute power to come from powerplant Y, if Z is unavailable. This second contract is for a term of four years, with delivery commencing on 1/1/11. These contracts are not linked. Although they were executed within three months of each other, they each specify a different powerplant as the primary delivery source. On the other hand, if both contracts specified that they were for power from powerplant X, with substitute power under the first contract coming from powerplant Y and under the second contract coming from powerplant Z, the two contracts *would be* linked. They would have been executed within three months of each other, and they would both specify the same powerplant as the *primary* delivery source. Furthermore, these linked contracts would have a term of five years or more, and therefore the EPS would apply. The first delivery would be on 1/1/09, and the final delivery is on 12/31/14. Thus the total term of these linked contracts would be six years. Finally, let us consider another variation on this scenario. Under this final variation both contracts designate powerplant X as the primary delivery source (even though they designate different powerplants as the source of substitute power), but the second contract has a term of only two years. Although the contracts are linked, the EPS would not apply, because the term of two contracts together is less than five years. (The first delivery would occur on 1/1/09, with the final delivery on 12/31/12.) The fact that the contracts were executed more than five years before the final delivery date is not relevant in determining the term of the contract.

For our next example, let us consider an LSE that uses an RFO procedure for soliciting contracts. The LSE puts out an RFO on 1/1/08. It receives bids on 2/1/08, and on 4/18/08 it executes a contract for unspecified sources with

counter-party A. This contract has a term of four years with delivery commencing on 1/1/09. In the meantime, on 4/1/08 the LSE has put out a second RFO. No bids of any kind are received under this RFO until 5/1/08. Counter-party A submits a bid on 5/1/08. This bid is accepted by the LSE and results in a second contract for unspecified sources with counter-party A. This second contract is executed on 6/18/08 and has a term of four years, with delivery commencing on 1/1/10. These contracts are not linked, even though they were executed within three months of each other. This result is due to the provision of the linkage rule that says that two contracts are not linked if they are "entered into as a result of separate RFOs and the contracts from the earlier RFO are executed before the later RFO has received any bids". In this example, the first contract resulted from an RFO and was executed before any bids were received under the second RFO. Thus the EPS does *not* apply to these two contracts, because neither of them individually has a term of five years or more. On the other hand, if the first contract was executed on 5/5/08, after bids were received on the second RFO, the contracts would be linked and their combined term would be five years (first delivery on 1/1/09, final delivery on 12/31/13).

For our final example, we will consider two contracts that are negotiated within three months of each other, even though their execution dates are more than three months apart. On 6/5/07, the LSE begins discussions with counter-party B about several possible contracts for unspecified power. They quickly reach agreement about a contract with a four-year term and deliveries commencing 1/1/08. This contract is executed on 7/15/07. Their discussion about a second contract for unspecified power, with a three-year term and deliveries commencing on 1/1/10, drag on for a long time, as the parties have difficulty agreeing on a price term for a contract extending so far into the future.

Eventually they do agree on a price term and execute this second contract on 12/15/07 (with a three-year term and deliveries commencing on 1/1/10). These two contracts are linked. The second contract was being negotiated at the same time as the first contract.[219] The total term of these linked contracts is five years (first delivery on 1/1/08, final delivery on 12/31/12).

It is important to note that the linkage rule is only one step in determining whether a particular group of linked contracts must comply with the EPS. It is simply used to determine whether the length of the linked contracts is sufficient for there to be a "contract with a term of five years or more." Thus, for example, if within a three-month period an LSE executes three contracts for the same specified source, that together have an initial delivery date of 1/1/08 and a final delivery date of 12/31/15 (and thus a total term of more than five years), but the source is not a "powerplant that is designed and intended to provide electricity at an annualized plant capacity factor of at least 60 percent" then the EPS will not apply.

5.6. Definition of Capacity Factor

In their opening comments on the final report, EPUC/CAC request clarification of the definition of capacity factor to be used in the EPS baseload screen. They point out that SB 1368 defines baseload using the term "annualized plant capacity factor," whereas the staff report defines covered resources based on their "average annual" capacity factor. They suggest formally defining "annualized" as an "annual average." In particular, they propose that the capacity factor be calculated by summing the total annual energy "deliveries" of

[219] Under this linkage rule, two contracts are linked so long as some of the negotiation for one of the contracts occurs within 3 months of the execution of the other.

a resource, averaging them over the year, and then dividing that average by the plant's maximum permitted capacity.[220]

The Merriam-Webster Online Dictionary defines annualize as: "to calculate or adjust to reflect a rate based on a full year." We therefore find it reasonable to define the term "annualized" to mean "annual average" as EPUC/CAC suggest, but with a significant caveat. The annual average must be calculated in a manner that is consistent with today's decision, that is, it must be based on the annual production of the underlying facility, and not just what might be delivered under a specific contract with an LSE. As IEP points out, a strict interpretation of ECAC/CAC's proposed definition could result in partial year contracts being treated in a manner that conflicts with today's determinations.[221]

Moreover, there are likely to be situations where more than a single year of annual electricity production will need to be considered in determining whether or not a powerplant is "designed and intended" to provide electricity at an annualized plant capacity factor of at least 60 percent. (§ 8340(a).) In fact, the definition of "plant capacity factor" provides for our consideration of more than a single year, in that it expresses the capacity factor as a ratio of electricity produced to electricity production at rated capacity "during a given time period." (§ 8340(l).) This makes sense, because a plant's operations may vary significantly from year to year, based on weather or economic conditions. However, if it were designed and intended to operate as baseload generation,

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[220] *Opening Comments of EPUC/CAC on the Final Workshop Report*, October 18, 2006, p. 11.

[221] See *Reply Comments and Legal Brief of the Independent Energy Producers Association on the Final Staff Workshop Report*, October 27, 2006, p. 5.

under the law it is subject to the EPS. Therefore, in their showing of whether the EPS applies to a new long-term financial commitment (other than new plant construction), LSEs should include historical plant capacity factors for the underlying facility or facilities to document the annualized plant capacity factor.

Consistent with the above, the definition of plant capacity factor provided in SB 1368 and our definition of what constitutes a "powerplant," we clarify what is meant by "annualized plant capacity factor" as follows:

> "An annualized plant capacity factor is the ratio of the annual amount of electricity produced, measured in kilowatthours, divided by the annual amount of electricity the powerplant could have produced if it had been operated at its maximum permitted capacity, expressed in kilowatthours."

We agree with EPUC/CAC's suggestion to use the term "permitted" in our definition of "plant capacity factor" to clarify what output should be used in the denominator of this equation (i.e., the maximum output designated by the manufacturer or the maximum output allowed under the operating permit). For this purpose, we believe that the maximum rated capacity allowed under the operating permit best captures the "designed *and intended*" language of the statute in those instances when permit provisions represent the effective constraint on the maximum output of the facility, rather than the manufacturer's rated capacity.

5.7. Long-Term Procurement Plans and the EPS

In our Long-Term Procurement Rulemaking (R.06-02-013), we directed SCE, PG&E and SDG&E to indicate in their long-term procurement plans (LTPPs) how they would comply with the EPS under consideration in this

proceeding.[222] Within sixty (60) days from the effective date of this decision, SCE, PG&E and SDG&E should update their LTPP filings in compliance with the adopted EPS rules, as necessary, to reflect today's determinations. If changes to the LTPP filing are necessary to show compliance with this decision, SCE, PG&E and SDG&E should file an Amendment to the LTPP, Volume 1, indicating whether the Amendment supersedes or adds to specific sections of the plan, with service on the service list in R.06-02-013. If additional rules related to GHG policy are adopted in the future, in between the biennial review process, SCE, PG&E and SDG&E should update their LTPPs using the standard procedure for amending those plans, i.e., currently they can update LTPPs in between the biennial review process via an Advice Letter filing.

We note that the Phase 2 Scoping Memo in R.06-02-013 did not require electric service providers and community choice aggregators to file LTPPs at this time.[223] If that ruling changes for subsequent years of LTPP filings, then electric service providers and community choice aggregators will be required to include in their LTPPs how they plan on complying with the EPS rules.

5.8. Other Compliance-Related Issues

Today's decision provides direction to LSEs on how to submit their EPS compliance filings, and what information to include in them. The Commission, Assigned Commissioner, ALJ and/or Commission staff retain the right to data request any of the LSEs, including the electric service providers, community choice aggregators or small electrical corporations, to ask for any copies of

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[222] *Assigned Commissioner's Ruling and Scoping Memo on the Long-Term Procurement Phase*, R.06-02-013, September 25, 2006, p. 24.

[223] *Ibid.*, p. 36.

contracts or procurement information that is deemed necessary to evaluate compliance with the EPS. Moreover, any LSE may be audited if the Commission or staff has any doubt that the LSE is forthcoming in its demonstration of EPS compliance.

This includes any information on related contracts that the Commission or its staff may deem relevant in determining whether the LSE is circumventing the EPS rule by entering into multiple contracts of less than five years duration.[224] This also includes any information on investments in retained generation, including deemed-compliant CCGTs, that the Commission or its staff may deem relevant in determining whether the LSE has complied with the interim EPS rules.

If any of the financial commitments entered into by LSEs appear to be out of compliance with the rules, the Commission may consider issuing an Order Instituting Investigation (OII) or take other appropriate action. If the Commission finds that the LSE did not comply with the EPS, the Commission will address the level of penalties in the OII proceeding or other procedural forum, as it deems appropriate.

In complying with today's requirements, any LSE that seeks confidentiality protection for data contained in its EPS-related submittals must follow the policies and procedures set forth in D.06-06-066.

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[224] Other "slicing and dicing" concerns discussed during the workshop process and in the draft and final recommendations (see final report at page 102) have become moot with today's determinations on size exemptions and the treatment of partial contracts.

6. Issues Raised by Parties Outside the Scope of Phase 1

Several parties raise issues in their comments that are outside the scope of Phase 1, which we mention briefly below.

Referencing § 8341(b)(6), Carson Hydrogen Power Project requests that we address policies to encourage "zero- or low-carbon generation resources" in this proceeding. Section 8341(b)(6) states:

> "A long-term financial commitment entered into through a zero- or low-carbon generating resource that is contracted for, on behalf of consumers of this state on a cost-of-service basis, shall be recoverable in rates, in a manner determined by the commission consistent with Section 380. The commission may, after a hearing, approve an increase from one-half to 1 percent in the return on investment by the third party entering into the contract with an electrical corporation with respect to investment in zero- or low-carbon generation resources authorized pursuant to this subdivision."

Commission overall policies addressing "zero- or low-carbon generation resources" are not within the scope of Phase 1. If an electrical corporation seeks Commission approval of a rate-of-return increase on investments made by third parties, as described in § 8341(b)(6), it may file such a request in our Long-Term Procurement Rulemaking (R.06-02-013), or its successor proceeding.

Calpine recommends that the Commission take additional steps to encourage long-term commitments with resources with emissions below the EPS limit, such as providing incentives to reward LSEs for contracting with lower emitting resources and resource owners for developing such resources. This recommendation is beyond the scope of Phase 1. In D.06-02-032, we discuss how we intend to pursue financial incentives for preferred resources in conjunction with a GHG emissions cap, and identified the resource-specific proceedings

where such "shareholder risk/return incentive mechanisms" will be considered. We also discuss our intent to pursue the concept of "allowance sale incentives" for superior performance in GHG reductions during Phase 2 of this proceeding.[225]

In post-workshop comments, San Francisco Community Power urges us to commit to a specific inventory of emission allowances on a date certain (e.g., January 1, 2007) for each LSE.. It would be premature, and beyond the scope of Phase 1, to establish target dates for these determinations in today's decision. The schedule for addressing this and other baseline-related issues for a load-based cap, including allowance allocations among individual LSEs, will be established during Phase 2 implementation of our adopted Procurement Incentive Framework, in coordination with CARB and other state agencies implementing AB 32. For similar reasons, we do not adopt PG&E's recommendations to "immediately" convene a Phase 1A in parallel with Phase 2 implementation of AB 32, in order to address issues related to the assignment of GHG emissions of unspecified power that would carry over in that phase.[226] The Phase 2 scoping and scheduling process underway by the Assigned Commissioner and ALJs is the appropriate procedural forum for considering how best to sequence and prioritize the myriad of issues related to implementing AB 32, rather than today's Phase 1 decision.

Finally, in its opening comments on the Proposed Decision, the Community Environmental Council (CE Council) urges us to include in today's decision a preliminary "lifecycle" analysis of net emissions for natural gas plants

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[225] D.06-02-032, pp. 30-32, 34-35.

[226] *Reply Comments of PG&E on Proposed Decision*, January 8, 2007, p. 3.

that may use liquefied natural gas (LNG), and to indicate that the EPS will be modified in the future in accordance with the Commission's findings regarding GHG emissions from LNG. A definition of "lifecycle analysis" (including where the lifecycle begins and ends) is not presented in CE Council's comments.[227] However, in the context of LNG, CE Council describes such an analysis as including the upstream carbon emissions associated with the extracting and shipping of LNG in addition to those resulting from the production of electricity at the natural gas plant.

The scoping of Phase 1 did not identify the issue that CE Council now raises in its comments on the Proposed Decision, namely, whether the Commission should undertake a lifecycle net emissions analysis to determine compliance with SB 1368, and if so, how that analysis should be conducted. Moreover, SB 1368 specifically directs us to consider lifecycle net emissions in one context only, and not in others, and we have followed that specific direction (e.g., for biomass, biogas or landfill gas-fueled plants where CO2 is removed from the atmosphere at one lifecycle stage and put into the atmosphere at another). If we were to go beyond that specific direction and take a lifecycle approach to other net emission calculations, we would have to do so for all other resources to treat them consistently--and not just for LNG as CE Council suggests. Taking such an approach was not raised during the scoping of Phase 1,

[227] For example, the lifecycle emissions concept could encompass the process for extracting fuel (e.g., uranium for nuclear powerplants), transportation of fuel to the powerplant, as well as the fabrication of the generation facility (e.g., the wind turbine, photovoltaic cells, etc.) that produces the electric power and any associated fuel disposal processes. We have no record in Phase 1 on the various approaches and methods for conducting a lifecycle analysis of GHG emissions to consider in making this determination.

during workshops or in pre- or post-workshop written comments. Even if it were, we do not have a sufficient record or time before the statute requires us to adopt an enforceable standard to take this approach for the interim EPS. For these reasons, we do not adopt CE Council's recommendation.

7. Federal Preemption Issues

In Section 4.8.3 above we address federal preemption arguments with respect to applying the EPS to QFs. In its Phase 1 legal brief, CEED raises a second federal preemption issue, namely whether adoption of the EPS conflicts with United States foreign policy. In its comments on the Proposed Decision, CEED raises, for the first time, other federal statutory preemption arguments.

CEED argues that "the President has articulated a federal policy of not mandating unilateral reductions in CO_2 emissions from United States sources because responsibility for committing to and implementing any binding emission controls to address global climate change must be shared by all nations, including developing nations. Moreover, Congress has endorsed the President's policy against requiring CO_2 emission reductions only from the United States and other developed countries."[228] However, the authorities they do cite (a letter and statements from the President and S. Res. 98, 105th Cong. (1997)) only establish, at most, a much less sweeping proposition concerning U.S. foreign policy: namely, that the United States has a foreign policy of not entering into treaties that do not require the curbing of $C0_2$ emissions from developing nations.[229] It is unclear how California, which is not proposing to sign any international agreement here, could be undermining such a policy. Ultimately,

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[228] *CEED's Opening Brief on Jurisdictional and Other Legal Issues,* June 30, 2006, p. 10.

CEED's argument seems to be that because the President does not wish to do anything about climate change until he can get recalcitrant developing countries to agree to curb their GHG emissions, that states are precluded from taking actions that can ameliorate the impacts of climate change on their citizens; because the President wants developing nations to do their share, therefore California cannot do its share. In short, we conclude that there is no conflict between California's adoption of an EPS and a federal foreign policy of not agreeing to international GHG treaties unless they include reductions by developing countries.[230]

In support of its argument, CEED cites to *Am. Ins. Ass'n* v. *Garamendi* (2003) 539 U.S. 396 and *Hines* v. *Davidowitz* (1941) 312 U.S. 52.[231] The situations in both of those cases are entirely different from the situation here. *Garamendi* involved a clear conflict between a state law and federal foreign policy expressed in an executive agreement that the President had entered into with foreign governments. Furthermore, the executive agreement concerned a matter traditionally within the scope of the President's federal foreign policy power. In addition, the state law was not in an area of traditional state jurisdiction. Indeed, the state law was aimed at insurance policies issued in Europe during the Holocaust era. *Hines* involved conflicting state and federal statutes for the registration of aliens. The Court in *Hines* recognized the treatment of aliens as

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[229] *Ibid.*, footnotes 23, 24 and 26.

[230] CEED's speculation that there might be some conflict in the future ignores the fact that if the U.S. does sign a GHG treaty or otherwise promulgate a GHG policy that is binding on the states, California will be required to bring its program into compliance if there is a conflict. *Ibid.*, p. 11.

[231] *Ibid.*, p. 9, footnote 21.

being distinctly a matter handled by the federal government in the arena of international affairs. The state law was directed at foreign citizens and was thereby, like the situation in *Garamendi*, not in an area of traditional state jurisdiction.

In its comments on the Proposed Decision, CEED cites to a third case, *Crosby* v. *Nat'l Foreign Trade Council* (2000) 530 U.S. 363.[232] Like both *Garamendi* and *Hines*, *Crosby* involved a clear conflict between differing state and federal statutory schemes. In *Crosby*, the conflicting state and federal laws involved sanctions regarding relations with Burma. Again, as in *Garamendi* and *Hines*, the state law in *Crosby* was aimed at regulating foreign relations and was therefore not in an area of traditional state regulation.

Here, in contrast, there is no conflict between: (1) policy statements by the federal government that it does not intend to enter into treaties with foreign governments that would require the United States to reduce GHG emissions unless developing countries do so as well; and (2) California law requiring that new long-term financial commitments, by California-regulated entities, for the production of electricity to be consumed in California, meet a GHG emissions standard. Furthermore, the regulation of air emissions is not traditionally within the exclusive parameters of the president's foreign policy powers. On the other hand, states traditionally have authority to: (1) reduce emissions to protect their own populations; and (2) protect ratepayers of state-regulated utilities.

Nowhere does CEED refer to any specific foreign policy statement, treaty or international agreement that clearly evidences the intent to preempt state

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[232] *CEED's Comments on Draft Interim Decision on Phase I Issues: Greenhouse Gas Emissions Performance Standard*, January 2, 2007, p. 21, fn. 28.

regulation of electric utilities selling electricity within the states' own borders. Instead, CEED argues that the EPS adopted in the Proposed Decision is preempted because it would purportedly conflict with the federal government's foreign and domestic policies on global climate change. However, with regard to foreign policy matters, the specific terms of a treaty or bilateral agreement must indicate that the state has been preempted on a specific subject. *See Wardair Can. Inc.* v. *Fla. Dep't of Revenue* (1986) 477 U.S. 1, 9-11 (State tax on foreign airlines' purchase of aviation fuel in state was not preempted by Chicago Convention's prohibition of local taxes for fuel on board an arriving foreign aircraft or by 70 bilateral agreements' prohibition of national taxes on aviation fuel).

In addition, when a treaty or agreement has not been signed or passed by the Executive Branch or Legislative Branch, it cannot preempt state law. *Ibid.* at 11. (Resolution of international organization endorsing exemption for international aircraft from all taxes does not have the force of law to preempt states' taxes even though the United States is a member of the organization). It is noteworthy that *Garamendi*, *Hines*, and *Crosby* all involved either federal statutes or executive agreements that had the force and effect of law. CEED has not cited to any statute, treaty or executive agreement that has the force and effect of law regarding the states' ability to regulate GHG emissions.

In its comments on the Proposed Decision, CEED also relies on a ruling in the Eastern District of California (*Central Valley Chrysler-Jeep* v. *Witherspoon*, E.D. Cal. Case No. 1:04-CV-6663- AWI-LJO, dated September 22, 2006). CEED claims that this ruling holds "that a state program that requires mandatory reductions in greenhouse gas emissions conflicts with United States foreign policy

addressing climate change."[233] However, as the Attorney General points out in its Reply to CEED's comments, the *Central Valley Chrysler-Jeep* ruling was, in fact, merely a preliminary ruling allowing the claim to go forward. The ruling was not on the merits of whether mandatory state greenhouse gas emissions programs conflict with United States foreign policy.[234]

The Attorney General further addresses CEED's comments by providing copies of express statements made by the federal government, which clearly establish that federal and domestic policy do not preclude states from taking measures to reduce GHG emissions.[235] As James L. Connaughton, Chairman of the White House Council on Environmental Quality, testified before the U.S. House of Representatives Committee on Government Reform (on July 20, 2006), "Domestically, in 2002, President Bush set an ambitious national goal to reduce the greenhouse gas intensity (emissions per unit of GDP) of the U.S. economy by

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[233] *Ibid.* at p. 21.

[234] *Attorney General's Phase I, Draft Interim Decision: Greenhouse Gas Emission Performance Standard Reply Brief of the People of the State of California,* January 8, 2007, p. 5. *Central Valley Chrysler-Jeep,* p. 40.

[235] The Attorney General requests that the Commission take official notice of statements of the following representatives of the federal government: James Connaughton, Chairman of the White House Counsel on Environmental Quality; and Harlan Watson, State Department Senior Climate Negotiator. We note that since these statements were attached to the Attorney General's Reply brief they are already part of the record of this proceeding. Nonetheless, we grant the request to take official notice of these statements. The Attorney General's documentation of these statements was submitted in support of its Motion for Summary Judgment to the court in the *Central Valley Chrysler-Jeep* case, subsequent to the ruling discussed above.

18 percent by 2012."[236] Also in 2002, "the President called for action at all levels of government and across all sectors. Many of our states and cities are experimenting with . . . portfolios of voluntary measures, incentives, and locally relevant mandatory measures. Many of these build on or partner with related federal programs." (p. 4) In a quote in the New York Times, regarding several states' efforts to decrease emissions by powerplants, Mr. Connaughton stated that the federal government "welcome[s] all efforts to help meet the president's goal for significantly reducing greenhouse gas intensity by investing in new, more efficient technologies."

In terms of foreign policy, Harlan Watson, State Department Senior Climate Negotiator, during international climate treaty negotiations (December 2003), stated in support of state policies:

> Finally, I would like to highlight the efforts being made by State and local governments in the United States to address climate change. Geographically, the United States encompasses vast and diverse climatic zones representative of all major regions of the world - polar, temperate, semi-tropical, and tropical - with different heating, cooling, and transportation needs and with different energy endowments. Such diversity allows our State and local government to act as laboratories where new and creative ideas and methods can be applied and shared with others and inform federal policy - a truly bottom-up approach to addressing climate change.[237]

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[236] *Testimony of James L. Connaughton, Chairman, White House Council on Environmental Quality, Before the United States House of Representatives Committee on Government Reform,* July 20, 2006, p. 2.

[237] *Statement to the Second Meeting of the Plenary, Ninth Session of the Conference of the Parties (COP-9) to the UN Framework Convention on Climate Change,* Milan, Italy (December 4, 2003), available at http://www.state.gov/g/oes/rls/rm/2003/26894.htm.

During the same negotiations, Mr. Watson also stated that:

> At the State level, 40 or 50 States have prepared GHG inventories, 27 States have completed climate change action plans, and 8 States have adopted voluntary GHG emissions goals. In addition, 13 States have adopted "Renewable Portfolio Standards" requiring electricity generators to gradually increase the portion of electricity produced from renewable resources such as wind, biomass, geothermal, and solar energy. And, at the local level, more than 140 local governments participating in the Cities for Climate Protection Campaign are developing cost-effective GHG reduction plans, setting goals, and reducing GHG emissions.[238]

Contrary to CEED's claims, far from preempting states through foreign policy or otherwise, the federal government recognizes the role of states in helping to reduce greenhouse gas emissions.

In its Comments to the Proposed Decision, CEED also claims that the EPS is preempted under the following federal statutes: the Global Climate Protection Act of 1987 (GCPA), the Energy Policy Acts of 1992 and 2005, and the Federal Power Act.

The fundamental inquiry in any preemption analysis is whether Congress intended to displace state law. Without express preemption in the statute or an actual conflict between prescriptions under the federal and state laws, there must be evidence of Congress' intent to preempt the specific field covered by the state law. *Wardair*, 477 U.S. at 6. Under preemption analysis the assumption is "that the historic police powers of the State were not superseded by the Federal Act unless that was the clear and manifest purpose of Congress." *Medtronic, Inc.* v.

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[238] *Ibid.*

Lohr (1996) 518 U.S. 470, 485 (1996) (internal citations omitted); *see also Pacific Gas & Elec. Co* v. *Cal.* (9th Cir. 2003) 350 F.3d 932, 943. Furthermore, when Congress has contemplated, but chosen not to create a federal scheme, there is no reason to infer from Congress' silence that states would be preempted from regulating that matter.[239]

CEED relies on the GCPA, the Energy Policy Act of 1992 and the Energy Policy Act of 2005 for the proposition that because Congress did not require nationwide standards on greenhouse gases, California is preempted from regulating in the area of greenhouse gases. However, CEED does not specify any provision of these Acts that preempts states from requiring its utilities to take actions to decrease GHG emissions. Indeed, in EPAct 2005, in the climate protection provisions involving electric utilities (Title XVI - Global Climate Change & Title XVII - Incentives for Innovative Technologies), only one provision mentions states. In the one place where Congress addresses state government activities, Congress explicitly recognizes the state commissions' authority to approve procurement contracts by their electric utilities and the states' rights to set emission standards. Energy Policy Act of 2005 § 1703(c)(1)(A)(iii) (One of the eligibility criteria for certain projects for the reduction of GHG emissions requires approval of a procurement contract by the "the relevant State public utility commission.") & (d) (Emission levels for projects must meet "applicable Federal or State emission limitation requirements."), Pub. L. No. 109-58, 119 Stat. 1120-22.

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[239] *See In re World Auxiliary Power Co.*(9th Cir. 2002) 303 F.3d 1120, 1131.

Likewise, the legislative history for the Energy Policy Act of 1992, which CEED refers to, does not make any specific references to states. The Energy Policy Act of 1992, itself however, expressly recognizes state action, again, indicating no intent on the part of Congress to preempt states. *See* Energy Policy Act of 1992 § 1602(a) (The federal government is required to "take into account . . . relevant Federal, State, and local requirements" in developing a least-cost energy strategy.) & *ibid.* at § 1605(b)(1)(C) (The federal government shall establish procedures for the accurate voluntary reporting of greenhouse gas emissions reductions achieved through state or federal requirements.), Pub. L. No. 102-486, 106 Stat. 2999-3000, 3003. (Title XVI - Global Climate Change).

For the GCPA, CEED cites to 15 U.S.C. §§ 2901, *et seq.* as support for preemption of states from regulation of GHG emissions. None of these sections deals with states except for 15 U.S.C. § 2904, which states that the National Climate Program Office shall "work with the National Academy of Sciences and other private, academic, State, and local groups in preparing and implementing [plans for the National Climate Program]." 15 U.S.C. § 2904(c)(2)(F). The Program may provide for various "State and regional services and functions . . ." 15 U.S.C. § 2904(d)(7). Instead of evidencing the intent to preempt states, all three of these Acts expressly provide for state activity and recognize state authority over, and participation in, regulation for the reduction of greenhouse gas emissions.

In CEED's comments on the Proposed Decision, it also claims that the EPS is preempted by the Federal Power Act, because of a purported "implied conflict" resulting from an alleged barrier to entry into the wholesale market. CEED points out that the FERC has exclusive authority over the wholesale market under the Federal Power Act.

The EPS, however, is not regulating wholesale generators or marketers. The EPS is regulating LSEs, which sell electric energy in the retail market in California. Under section 201(b) of the Federal Power Act, 16 U.S.C. § 824(b), Congress preserved the States' authority over such retail sales service and the public utilities which provide such retail sales service.[240]

As part of this regulation of the retail sales service, the Commission has historically regulated procurement practices of the California public utilities. The EPS is an essential component of the Commission current regulation of the procurement practices of the retail sellers of electric energy in California. However, the Commission is not regulating coal-fired generators or any other generators selling in the wholesale market. Wholesale generators or marketers may continue to sell electric energy to California LSEs under: existing contracts, new contracts of less than five years, or new contracts with powerplants that have capacity factors of less than 60%. In addition, wholesale generators or marketers have the opportunity to sell to California LSEs under new baseload contracts of five years or greater to the extent that they meet the EPS. Generators or marketers utilizing high GHG-emitters, such as coal-fired generation plants, would have to use technology that reduces GHG emissions to be eligible under the EPS program. Of course, generators utilizing coal-fired generation plants and all other wholesale marketers are also free to sell their electric energy to purchasers outside of California. The EPS only applies to purchasers of electric energy for consumption in California.

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[240] *See New York* v. *FERC* (2002) 535 U.S. 1, 20, 23, 28; *see also Connecticut Light and Power Co.* v. *FPC*, (1945) 324 U. S. 515, 523-531.

CEED has not cited any FERC decision mandating the California LSEs to enter into new baseload contracts for electric energy from coal-fired generation plants, because there are no such decisions. Under section 201(b) of the Federal Power Act, 16 U.S.C. § 824(b), FERC does not have jurisdiction over retail sellers of electric energy, including their procurement decisions. FERC regulates the wholesale sellers, not the resource portfolios, including procurement choices, of the buyer. As FERC has stated in numerous decisions, FERC leaves the reasonableness of the procurement decisions to the state commissions, because FERC does not view its "responsibilities under the Federal Power Act as including a determination that the purchaser has purchased wisely or has made the best deal available."[241]

Indeed, FERC has acknowledged that with regard to the retail electric market, "state regulatory commissions and state legislatures have traditionally developed social and environmental programs suited to the circumstances of their states. ... Nothing in [FERC's Order No. 888] is inconsistent with traditional state regulatory authority in this area."[242] In *New York* v. *FERC*, which upheld FERC's Order No. 888, the United States Supreme Court explicitly relied upon and quoted FERC's statement that:

> 'This Final Rule will not affect or encroach upon state authority in such traditional areas as the authority over local service issues, including reliability of local service; administration of integrated resource planning and utility buy-side and demand-side decisions, including DSM [demand-side management];

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[241] *See, e.g., Ameren Energy Marketing Company* (2001) 96 FERC ¶ 61,306 at 62,189 & n. 18 (and cases cited therein).

[242] *See* Order No. 888, FERC Stats. & Regs., Regs. Preambles, Jan. 1991-June 1996, ¶ 31,036, p. 31,782 (1996).

> [and] authority over utility generation and resource portfolios.'[243]

The FERC is well aware that certain states require that the resource portfolios of their state-regulated utilities include generation and procurement from sources that will cause minimal damage to the environment. For example, in *American Ref-Fuel Co., et al.,* FERC referred to 13 states that have programs with renewable energy credits (RECs) premised on promoting goals, such as improved air and water quality and reduction of greenhouse gas emissions.[244] FERC held that its avoided cost regulations for QFs under PURPA did not contemplate the existence of RECs, and, therefore, the determinations concerning state-created RECs *must be based upon state law.*[245] Thus, FERC recognized the authority of the states to regulate in the area of greenhouse gas reductions. In short, there is no implied or actual conflict between FERC and the CPUC concerning the EPS.

It is therefore clear that the Federal Power Act does not preempt state regulation of procurement choices by retail sellers of electric energy, including programs designed to reduce GHG, such as the EPS in the State of California. The Federal Power Act explicitly preserved the states' regulation of the retail market. As the Supreme Court has stated, this may well have been because "the 'insulated chambers of the states' are still laboratories where many lessons in

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[243] *See New York* v. *FERC* , 535 U.S. at 24, *quoting* Order No 888 at 31,372, n. 544.

[244] *See American Ref-Fuel Co., et al.* (2004) 107 FERC ¶ 61,016 at PP 2-3.

[245] *See ibid.* at PP 6, 16.

regulation may be learned by trial and error on a small scale without involving a whole national industry in every experiment."[246]

For all of the foregoing reasons we conclude that there is no conflict between SB 1368 and our implementation of it, on the one hand, and federal law or foreign policy on the other hand.

8. Commerce Clause Issues

The Commerce Clause states that: "Congress shall have [the] [p]ower ... to regulate Commerce with foreign [n]ations, and among the several [s]tates."[247] The negative implication, or dormant aspect, of the Commerce Clause limits the ability of individual states to impede the flow of interstate commerce.[248] Dormant Commerce Clause doctrine consists of three analytical frameworks. First, a state rule that facially discriminates against other states in order to protect local economic interests will generally be found invalid.[249] Second, when a state rule does not facially discriminate against out-of-state economic interests, the *Pike* balancing test will be applied. Under *Pike*, a state enactment "will be upheld unless the burden imposed on such commerce is clearly excessive in relation to the putative local benefits."[250] Third, a state rule must not regulate

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[246] *See Connecticut Light and Power Co.* v. *FPC*, 324 U. S. at 530.

[247] U.S. Const. art. I, § 8, cls. 1, 3.

[248] *See, e.g., H. P. Hood & Sons, Inc.* v. *Du Mond* (1949) 336 U.S. 525, 533-36.

[249] *See, e.g., Oregon Waste Systems, Inc.* v. *Department of Environmental Quality of the State of Oregon* (1994) 511 U.S. 93, 100-101; *but see Maine* v. *Taylor* (1986) 477 U.S. 131, 151-52 (Supreme Court upheld a discriminatory rule that furthered legitimate state interests where there were no reasonable, nondiscriminatory alternatives).

[250] *Pike* v. *Bruce Church, Inc.* (1970) 397 U.S. 137, 142.

extraterritorially.[251] The EPS does not run awry of any of these tests and is thus valid under the Commerce Clause.

8.1. The EPS does not Discriminate Against Interstate Commerce

Any party challenging the constitutional validity of a regulation under the dormant Commerce Clause bears the burden of demonstrating discrimination.[252] CEED argues that the EPS has a discriminatory effect on interstate commerce that violates the dormant Commerce Clause.[253] Citing *City of Philadelphia* for the principle that: "[a] state cannot block imports from other states, nor exports from within its boundaries, without offending the Constitution,"[254] CEED argues that the proposed EPS is unconstitutional because it would limit the ability of out-of-state coal-fueled generation plants to export their electricity into California.[255]

The EPS is distinguishable from the statute in *City of Philadelphia* for two reasons. First, the statute in *City of Philadelphia* prevented certain products from entering New Jersey. Under the EPS, electricity generated from high-GHG emitters can still be sold to California LSEs under existing contracts, or under new or renewal contracts of less than five years. In addition, coal-fired and other plants that use technology that reduces GHG emissions could meet the EPS.

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[251] *See, e.g., Healy* v. *Beer Institute* (1989) 491 U.S. 324, 336-37.

[252] *See Hughes* v. *Oklahoma* (1979) 441 U.S. 322, 336.

[253] *See, e.g., CEED's Opening Comments on Final Workshop Report,* October 18, 2006, p. 19. Similar Commerce Clause arguments were addressed in a related proceeding, D.06-06-071, "Order Denying Rehearing of Decision 06-02-032" (June 29, 2006).

[254] *See, e.g., CEED's Reply Brief on Jurisdictional and Other Legal Issues,* July 11, 2006, p. 4 (*Citing City of Philadelphia* v. *New Jersey* (1970) 437 U.S. 617, 620.).

[255] *See, e.g., CEED's Opening Brief on Jurisdictional and Other Legal Issues,* June 30, 2006, p. 7.

More importantly, the EPS does not discriminate based on geographic origin. The salience of geographic neutrality in dormant Commerce Clause analysis was aptly stated in Environmental Defense's Reply Comments to the Proposed Decision.[256] In *City of Philadelphia*, the New Jersey statute prohibited the importation of "solid or liquid waste which originated outside the territorial limits of the State."[257] The Court explained: "whatever New Jersey's ultimate purpose, it may not be accomplished by discriminating against articles of commerce coming from outside the State unless there is some reason, *apart from their origin*, to treat them differently."[258] In sharp contrast, the geographic locality of a high-GHG emitter is irrelevant under the EPS.[259] An LSE is free to enter into long-term contracts with both in-state and out-of-state generators because the EPS makes no distinctions between in-state and out-of-state sources of electricity. Indeed, the Attorney General notes that: "under the [EPS], a substantial amount of electricity generated out-of-state would [meet the EPS and therefore] continue

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[256] *Reply of Environmental Defense to Comments on Draft Interim Decision on Phase 1 Issues: Greenhouse Gas Emissions Performance Standard*, January 8, 2007, p. 1 (*Citing Kleenwell Biohazard Waste and General Ecology Consultants, Inc.* v. *Nelson* (9th Cir. 1995) 48 F.3d 391, 397-98; *Hass* v. *Oregon State Bar* (9th Cir. 1989) 883 F.2d 1453, 1462.).

[257] *City of Philadelphia* v. *New Jersey*, 437 U.S. at 618 (*Emphasis added*).

[258] *City of Philadelphia* v. *New Jersey*, 437 U.S. at 627-28 (*Emphasis added*).

[259] CEED makes the claim that the "Order itself concedes, 'non-California generators . . . must adjust their behavior' to comply with CPUC's GHG cap (and presumably with the interim EPS as well)." (*See, e.g., CEED's Opening Brief on Jurisdictional and Other Legal Issues,* June 30, 2006, p. 6.) The complete sentence on page 23 of D. 06-02-032, "The Opinion on Procurement Incentives Framework" (February 16, 2006), reads: "*California and* non-California generators are subject to the cap and must adjust their behavior accordingly." (*Emphasis added.*)

to be available for procurement"[260] For these reasons, we find CEED's argument to be without merit.

CEED additionally argues that the EPS discriminates against interstate commerce by treating California firms more favorably than out-of-state firms. CEED states that: "the 60 percent capacity factor exempts the majority of California's in-state generators from the EPS."[261] This is a comparison between apples and oranges.

The EPS covers the California LSEs' long-term baseload procurement contracts. Most of the parties at the Commission's workshop on June 21-23, 2006, agreed that the EPS should apply to baseload generation plants that are intended to operate year-long at a high-capacity factor, because these plants would provide the bulk of the LSEs' open procurement needs and the most significant amounts of GHG emissions. There was some disagreement as to whether the capacity factor should be at least 50% or 60%. However, most parties agreed with the 60% capacity factor, because the utilities' data showed that a 60% (or greater) capacity factor would capture 78% of the utilities' 2012 open procurement needs and 72% of the associated CO_2 emissions.[262]

On the other hand, there was general agreement at the Commission's workshop that the EPS should not apply to generation plants that operate at a

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[260] *Reply Brief to CEED for the People of the State of California,* Oct. 31, 2006, p. 5 (*Citing CO_2 Emission from Coal and Natural Gas from WECC Power Plants with High Capacity Factor in 2005* (CEC, Oct. 27, 2006).). According to this CEC report, at least 22 major out-of-state plants would meet the EPS.

[261] *CEED's Comments on Draft Workshop Report,* September 8, 2006, p. 15.

[262] *See* Draft Workshop Report, August 21, 2006, pp. 21-23, and its Summary of Comments, Responses to Workshop Question # 4, p. 47. Subsequently, the 60% capacity factor was codified by SB 1368 § 2. *See Public Utilities Code* § 8340(a).

low-capacity factor to meet peaking or other reliability needs. Parties agreed that the EPS should not apply to these types of generation plants because it could be detrimental to the reliability and performance of the transmission grid and it would not reduce a significant amount of additional CO_2 emissions.[263] While the California utilities procure electricity from some out-of-state low-capacity factor plants, both the Commission and the California ISO have recognized that many local low-capacity factor plants are required to generate electricity at specific locations for the operational reliability of the electric transmission grid.[264]

In view of the above, long-term baseload generation operating at a capacity factor of 60% or greater performs a totally different function and would be responsible for a much greater amount of GHG emissions than low-capacity factor generation (such as peakers) operating at a capacity factor of less than 60%; including many which are operating only 10% or 20% of the time during the year and are essential for the reliability of the grid. Thus, the generators competing under the EPS for long-term, high-capacity factor baseload contracts are not similarly situated with low-capacity factor generation plants. Consequently, there is no legitimate claim of discrimination under the dormant Commerce Clause based upon the exemption of low-capacity factor generators from the EPS.[265]

Furthermore, the Attorney General states that: "[t]he CEC currently estimates that more in-state than out-of-state [baseload] generation facilities

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[263] *See* Draft Workshop Report, August 21, 2006, pp. 21-23, and its Summary of Comments, Responses to Workshop Question # 4, p. 47.

[264] *See* D.06-06-064, "Opinion on Local Resource Adequacy Requirements" (June 29, 2006).

would fail to meet the [EPS]" and that "more imported electricity than locally generated electricity from facilities to which the [EPS] is to be applied may meet the [EPS]."[266] Regardless, any shift towards or away from out-of-state resources is speculative at this point, and could not possibly indicate discriminatory intent. We therefore reject CEED's argument as invalid.

CEED further argues that the EPS (and the GHG cap to be implemented in Phase 2) "places heightened financial burdens on the construction of new coal-fueled powerplants in neighboring states."[267] This is based on the practice of using pre-construction contracts to secure financing for powerplant construction.[268] CEED further argues that the EPS therefore provides California firms with a "significant competitive advantage" in securing financing.[269]

The dormant Commerce Clause does not require California to protect the pecuniary interests of out-of-state coal burners.[270] Moreover, CEED's argument does not show that California firms will have a significant competitive advantage. As stated above, both California firms and out-of-state firms are covered under the EPS. The Supreme Court has observed that the Commerce Clause "protects the interstate market, not particular interstate firms, from

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[265] *See General Motors Corp.* v. *Tracy* (1997) 519 U.S. 278, 297-310.

[266] The Attorney General notes that: "[t]hese estimates may change when fuel use for non-electricity production is accounted for." *Reply Brief to CEED Comments for the People of the State of California*, Oct. 31, 2006, p. 5 (*Citing CO2 Emission from Coal and Natural Gas from WECC Power Plants with High Capacity Factor in 2005* (CEC, Oct. 27, 2006).).

[267] *See, e.g., CEED's Comments on Draft Workshop Report*, September 8, 2006, p. 17.

[268] *See, e.g., CEED's Comments on Draft Workshop Report*, September 8, 2006, pp. 17-18.

[269] *See, e.g., CEED's Comments on Draft Workshop Report*, September 8, 2006, p. 18.

[270] *See Exxon Corp.* v. *Maryland* (1978) 437 U.S. 117, 127-28.

prohibitive or burdensome regulations."[271] We find CEED's argument to be without merit.

CEED further complains that there is currently no cost-effective technology that would allow coal burners to meet the EPS[272] and also argues that the EPS would somehow hinder advanced clean coal technology development.[273] As NRDC, TURN, UCS and WRA note, there are already two planned generation facilities that intend to implement CO_2 sequestration, from day one of the plants' operation.[274] Thus, clean coal technology is now under development. By setting a GHG emissions limit, the EPS would create an incentive to further the development of clean coal technology, rather than hinder it. Conversely, allowing California to remain reliant on high GHG-emitting energy sources would serve as a disincentive for the advancement of environmentally sound coal technology. Regardless, as stated above, California is not required to protect the interests of "particular interstate firms."[275] We reject CEED's argument.

No party has met the burden of demonstrating discrimination. Therefore, we conclude that the EPS is an evenhanded regulation that does not discriminate against interstate commerce.

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[271] *Id.*

[272] *See, e.g., CEED's Comments on Draft Workshop Report,* September 8, 2006, pp. 13-14.

[273] *See, e.g., CEED's Comments on Draft Workshop Report,* September 8, 2006, pp. 12-13.

[274] *Opening Comments/Legal Brief on Final Workshop Report of NRDC/TURN/UCS/WRA,* October 18, 2006, p. 22.

[275] *Exxon Corp.* v. *Maryland,* 437 U.S. at 127-28.

8.2. *Pike* Balancing Test

When a state enactment is not facially discriminatory, the *Pike* balancing test is generally applied. In *Pike* v. *Bruce Church* (1970) 397 U.S. 137, the Supreme Court established this test that weighs the local benefits against the burdens on interstate commerce, in order to determine if a particular state regulation violates the dormant Commerce Clause. A regulation's burdens on interstate commerce must be "clearly excessive" in relation to the local benefits in order for a regulation to be struck down under *Pike*.[276] As Environmental Defense points out, the burden of proving "excessiveness" would fall on a party challenging a regulation.[277]

8.2.1. The EPS has Substantial Local Benefits

Despite the restrictions of the dormant Commerce Clause, a state retains general police powers to regulate legitimate local concerns.[278] In SB 1368, the Legislature has made specific legislative findings regarding the local benefits of the EPS.[279] SB 1368 reads: "[g]lobal warming will have serious adverse consequences on the economy, health and environment of California."[280]

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[276] 397 U.S. at 142.

[277] *Reply of Environmental Defense to Comments on Draft Interim Decision on Phase 1 Issues: Greenhouse Gas Emissions Performance Standard*, January 8, 2007, p. 3 (*Citing Pharmaceutical Care Management Ass'n* v. *Rowe* (1st Cir. 2005) 429 F.3d 294, 313.).

[278] *Maine* v. *Taylor*, 477 U.S. at 138.

[279] CEED previously argued that: "in the absence of specific findings regarding putative local benefits, the proposed EPS presumptively violates the Commerce Clause." (*CEED's Reply Brief on Jurisdictional and Other Legal Issues*, July 11, 2006, p. 3.) This point has become moot with the passage of SB 1368.

[280] SB 1368, Section 1, (a).

Regarding economic benefits, the Legislature found that "federal regulation of emissions of greenhouse gases is likely"[281] "over the next decade"[282] and that SB 1368 serves to "reduce potential exposure of California customers for future pollution-control costs."[283] SB 1368 also reduces "potential exposure of California consumers to future reliability problems in electricity supplies."[284] Thus, the EPS serves to protect ratepayers from the costs and risks of complying with future laws and regulations that will further limit the emission of GHG gases in the process of generating electricity. If Californians are reliant on high-GHG emitting sources, whether in-state or out-of-state, future regulations could have a devastating impact on the California economy. Non-compliant energy sources could be forced to refurbish their facilities to meet these new standards, and the costs could be shifted to consumers. Whether or not costs are shifted, plants would likely be unable to continue supplying as much power to California while they are refurbishing. Further, the EPS encourages a wide range of clean energy sources, which protects the reliability of the grid. It is a legitimate local purpose to protect California consumers from financial risks in an evolving regulatory scheme, while ensuring a continuous supply of electricity for California customers.

Regarding the health and environment of California, we look to the legislative findings of AB 32 and the Final Climate Action Team Report to the

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[281] SB 1368 Section 1, (f).

[282] SB 1368 Section 1 (e).

[283] SB 1368 Section 1, (i).

[284] SB 1368 Section 1, (j).

Governor and the Legislature (Presented to the Legislature in March, 2006) (CATR).[285]

In AB 32, the Legislature found that:

> "(a) Global warming poses a serious threat to the economic well-being, public health, natural resources, and the environment of California. The potential adverse impacts of global warming include the exacerbation of air quality problems, a reduction in the quality and supply of water to the state from the Sierra snowpack, a rise in sea levels resulting in displacement of thousands of coastal businesses and residences, damage to marine ecosystems and the natural environment, and an increase in the incidences of infectious diseases, asthma, and other human health-related problems."[286]

GHG emissions contribute to climate change.[287] By increasing the number of extremely hot days, and the "frequency, duration, and intensity of conditions conducive to air pollution formation, oppressive heat, and wildfires," the public health of Californians could be dramatically affected.[288] Climate change is also likely to increase infectious disease vectors such as mosquitoes, ticks, fleas and rodents, which would effectuate the negative health consequences discussed in AB 32.[289] Similarly, climate change can increase asthma triggers such as pollen, dust mites, and molds.[290] The decreases to the Sierra Nevada snowpack

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[285] The CATR was drafted as part of a multi-agency effort to address climate change and its effects on California.

[286] California Health & Safety Code § 38501(a).

[287] Final Climate Action Team Report to the Governor and the Legislature, March, 2006, pp. 19-24.

[288] *Id.* at 25-27.

[289] *Id.* at 27.

[290] *Id.*

mentioned in AB 32 would have far-reaching effects on California's water supply.[291] The snowpack provides a natural water supply to Californians, including agricultural growers.[292] Loss of the snowpack would result in decreased runoff, which would reduce the availability of the already overstretched water supply.[293] Electric supply from hydroelectric powerplants is also likely to diminish, while demand continues to rise.[294] The rise in sea level described in AB 32 could submerge many of California's beaches and estuaries.[295] The occurrences of extreme oceanic events are also expected to rise with sea levels.[296]

The Attorney General introduced into the record substantial materials that corroborate these findings, and the linkage between anthropogenic climate change and negative health and safety impacts on California.[297] For instance, Dr. Reinhard E. Flick states that "all beaches in California will be negatively affected" as the result of climate change.[298] Dr. Michael Hanemann notes that

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[291] *Id.* at 28-29.

[292] *Id.*

[293] *Id.* A state's right to protect its water supply is well-established. (*See, e.g., Proctor and Gamble* v. *City of Chicago* (7th Cir. 1975) 509 F.2d 69 (Upheld city ordinance forbidding the sale and use of detergents containing phosphates, which had a detrimental effect on the water supply.).)

[294] Final Climate Action Team Report to the Governor and the Legislature, March, 2006, p. 36.

[295] *Id.* at 31.

[296] *Id.* at 33.

[297] *Phase 1, Pre-Workshop Comments of the People of the State of California,* June 12, 2006, Exs. A-L.

[298] *Phase 1, Pre-Workshop Comments of the People of the State of California,* June 12, 2006, Ex. F, p. 2.

climate change would reduce California's water supply while increasing water demand.[299] We thus conclude that the EPS has substantial local benefits.

8.2.2. The EPS does not Excessively Burden Interstate Commerce

As noted above, CEED argues that the EPS will burden interstate commerce because it would somehow limit the construction of new coal-fueled plants and because clean coal technology is not commercially feasible. We have already shown how these alleged "burdens" are nondiscriminatory.
CEED also makes the speculative claim that the EPS would decrease the price of electricity sold by some out-of-state generators.[300] In its Reply Comments to the Proposed Decision, Environmental Defense notes that: "CEED's focus on this one segment of the interstate market . . . is insufficient to make out a burden on *interstate commerce*."[301] Environmental Defense further remarks that CEED is seeking to establish an impermissible burden by "selectively characterizing the affected market."[302] We agree that CEED is selectively characterizing the

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[299] *Phase 1, Pre-Workshop Comments of the People of the State of California,* June 12, 2006, Ex. G, p. 13.

[300] *See, e.g., CEED's Comments on Draft Workshop Report,* September 8, 2006, p. 17.

[301] *Reply of Environmental Defense to Comments on Draft Interim Decision on Phase 1 Issues: Greenhouse Gas Emissions Performance Standard,* January 8, 2007, p. 3.

[302] *Reply of Environmental Defense to Comments on Draft Interim Decision on Phase 1 Issues: Greenhouse Gas Emissions Performance Standard,* January 8, 2007, p. 4 (Citing *Kleenwell Biohazard* v. *Nelson*, 48 F.3d at 397-98; *Pharmaceutical Care v. Rowe*, 429 F.3d at 313; *National Solid Waste Management Ass'n* v. *Pine Belt Regional Solid Waste Management Authority* (5th Cir. 2004) 389 F.3d 491, 502 ("while the ordinances may have the effect of shifting some business away from plaintiffs, as the ordinances increase their costs and make them relatively less competitive, this result does not mean that the ordinances burden interstate commerce"; *International Truck and Engine Corp.* v. *Bray* (5th Cir. 2004) 372 F.3d 717, 727 ("[t]he fact that a regulation causes some business to shift from one supplier to another does not mean that the regulation burdens commerce"); *Brown & Williamson Tobacco Corp.* v. *Pataki*

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interstate market in order to inflate the purported burden. The EPS would affect electric generators that are high-GHG emitters and seek to enter into new long-term baseload contracts with California LSEs. However, this would only affect those generation companies to the extent they also refuse to refurbish their powerplants, or build new powerplants, with technology that limits GHG emissions such that they comply with the EPS. Beyond this very specific class, out-of-state generators would generally be able to meet the EPS. The overall interstate market is not being overly burdened.

More generally, CEED argues that: "the reality of California's energy market dictates that the [EPS] will primarily preclude out-of-state suppliers from competing in California markets"[303] and that the EPS burdens the economies of other states more than California.[304] CEED further argues that through coal displacement, various interstate geographic regions of the United States would be negatively impacted in the future.[305]

CEED presents a report by "Energy Ventures Analysis, Inc." (EVA)[306] which states that: "[b]aseload power imported from the Southwest would be far harder hit than generation from the Pacific Northwest. Both major importing

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(2d Cir. 2003) 320 F.3d 200, 213 ("The fact that these particular Plaintiffs may be priced out of the retail cigarette market does not establish a discriminatory effect.").).

[303] *See, e.g., CEED's Comments on Draft Workshop Report,* September 8, 2006, p. 15.

[304] *CEED's Comments on Draft Workshop Report,* September 8, 2006, Ex. 1, pp. 12-13.

[305] *CEED's Comments on Draft Workshop Report,* September 8, 2006, Exs. 4, 5, 6.

[306] Energy Ventures Analysis, Inc. (EVA) is a Virginia-based consulting firm which states on its website that is has assisted with: "[c]oal turnaround management and/or liquidations, including assuming coal company CEO and administrative responsibility." (<http://www.evainc.com/coal.htm>.)

areas would be hit much harder than in-state California plants."[307] The report speculates that 8-52 % of the existing Pacific Northwest imports would not meet the EPS, and that 54-86 % of the existing Southwest imports would not meet the EPS.[308] However, assuming arguendo these numbers were accurate, as much as 92% of the existing Pacific Northwest imports would meet the EPS, and as much as 46% of the existing Southwest imports would meet the EPS. Moreover, generators may make changes to existing generation plants or construct new out-of-state generation plants, in order to meet the EPS.

We find the EVA report unpersuasive. Indeed, reducing reliance on high-GHG emitting resources is a major goal of the EPS. Whether one out-of-state geographic region may be impacted more than another is not relevant here because the concern underlying the dormant Commerce Clause is economic protectionism of in-state interests.

CEED also attaches a study purporting to show various costs that will be incurred as coal is displaced by other fuels. However, the authors of the study cautioned that their analysis "is not intended to measure the impacts of any specific policy that could result in decreased coal production or utilization."[309] Environmental externalities such as pollution and GHG emissions were not considered in the study.[310] In any event, the fact that national displacement of

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[307] *CEED's Comments on Draft Workshop Report,* September 8, 2006, Ex. 1, p. 12.

[308] *CEED's Comments on Draft Workshop Report,* September 8, 2006, Ex. 1, p. 13.

[309] *The Center for Energy and Economic Development's Comments on Draft Workshop Report,* September 8, 2006, Ex. 5, p. 18.

[310] *The Center for Energy and Economic Development's Comments on Draft Workshop Report,* September 8, 2006, Ex. 5, pp. 18-19.

coal may have some economic effects does not establish an impermissible burden on interstate commerce.[311]

Overall, the argument CEED raises is analogous to a failed argument in *Minnesota* v. *Clover Leaf Creamery* (1981) 449 U.S. 456. In *Clover Leaf Creamery*, the Court upheld a Minnesota statute that banned the retail sale of milk in plastic nonreturnable, nonrefillable containers, but allowed such sale in other types of nonreturnable, nonrefillable containers.[312] The opponents of the statute argued that the "plastic resin . . . used for making plastic nonreturnable milk jugs, is produced entirely by non-Minnesota firms, while pulpwood, used for making paperboard, is a major Minnesota product."[313] The Supreme Court responded: "[e]ven granting that the out-of-state plastics industry is burdened relatively more heavily than the Minnesota pulpwood industry, we find that this burden is not 'clearly excessive' in light of the substantial state interest in promoting conservation of energy and other natural resources."[314]

As in *Clover Leaf Creamery*, the burdens cited by CEED cannot be deemed "clearly excessive" in light of the substantial local benefits of the EPS. Citing an October 30, 2006 Data Request Response from PG&E, SDG&E, and SCE, DRA points out that: "[a]s a practical matter, it appears that the duration of many

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[311] This study does not purport to attack the effects of the EPS per se, but rather deals with a nationwide trend, which DRA aptly points out "will not happen overnight." (*DRA's Written Reply to the Supplemental Material CEED on Commerce Clause Issues*, Nov. 1, 2006, p. 11.) Aside from that, the failure to incorporate the impact of externalities severely limits its usefulness in a dormant Commerce Clause analysis. DRA points to research that assessed such externalities. (*Id.* at pp. 11-14.)

[312] 449 U.S. 456.

[313] *Minnesota* v. *Clover Leaf Creamery*, 449 U.S. at 473.

[314] *Id.*

energy contracts is less than five years."[315] As stated above, coal-based and other high-GHG emitting power sources, can still sell to California LSEs under these short-term contracts, as well as existing contracts.[316] Thus, the speculative costs of the EPS cannot be deemed "clearly excessive" when weighed against the important local benefits of protecting ratepayers and the California environment.[317]

For all the reasons stated above, we conclude that the alleged burdens are incidental and not clearly excessive in relation to the substantial local benefits of the EPS.

8.3. The EPS is not an "Extraterritorial" Regulation

Like facially discriminatory regulations, an "extraterritorial" regulation is generally considered to be invalid per se.[318] In this context, extraterritorial regulation means regulation that impacts commerce that occurs "wholly" outside the state.[319]

CEED argues that the EPS will have an impermissible extraterritorial effect on interstate commerce. More specifically, CEED argues that the EPS will have the effect "of regulating the GHG emissions of out-of-state generators selling into

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[315] *The Division of Ratepayer Advocates' Written Reply to the Supplemental Material of CEED on Commerce Clause Issues*, Nov. 1, 2006, p. 7.

[316] Also, nothing in the EPS prohibits high-GHG emitters from transmitting electricity through the California grid to other states and nations.

[317] *See Minnesota* v. *Clover Leaf Creamery*, 449 U.S. 456; *Exxon Corp.* v. *Maryland*, 437 U.S. 117; *Cf. Huron Portland Cement Co.* v. *City of Detroit* (1960) 362 U.S. 440.

[318] *See, e.g., Brown-Forman Distillers Corp.* v. *New York State Liquor Authority* (1986) 476 U.S. 573, 579.

[319] *Edgar* v. *MITE Corp.* (1982) 457 U.S. 624, 642-43 (plur. opn.).

the California market, thus unlawfully controlling commercial conduct beyond the borders of California."[320] In support of this argument, CEED cites *Healy* v. *Beer Institute* (1989) 491 U.S. 324, 336, for the proposition that: "[t]he critical inquiry is whether the practical effect of the regulation is to control conduct beyond the boundaries of the State." However, the practical effect of the Connecticut law challenged in *Healy* was that brewers could not offer volume discounts in Massachusetts, New York and Rhode Island, where they were legal. If they did so, the volume discount would have become the ceiling price for all sales in Connecticut, which did not allow volume discounts.[321] The EPS, however, does not have the practical effect of setting the price, or any other conditions, of sales in other states.

Further, the EPS does not directly regulate commerce that occurs "wholly out-of-state." It only regulates the procurement practices and contracts of California LSEs buying for the California retail market. As the Ninth Circuit explained in *Gravquick A/S* v. *Trimble Navigation International Ltd.* (9th Cir. 2003) 323 F.3d 1219, 1224, cases finding extraterritorial regulation "deal with laws that regulate out-of-state parties directly, not through contract."[322] The Ninth Circuit held that when a state regulates contractual relationships in which at least one party is located within California, it does not regulate commerce entirely outside of the State of California.[323]

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[320] *See, e.g., CEED's Comments on Draft Workshop Report,* September 8, 2006, p. 18.

[321] *Healy* v. *Beer,* 491 U.S. at 339.

[322] *See Healy* v. *Beer,* 491 U.S. at 343 (Supreme Court invalidated statute that prevented sale of alcohol at a price higher than that sold in neighboring states.).

[323] *Gravquick A/S* v. *Trimble Navigation International Ltd.,* 323 F.3d at 1224.

Also, SCE argues that: "[c]ourts have repeatedly struck down state laws that burden interstate commerce by conditioning access to the local market on compliance with local environmental policies."[324] However none of the cases cited by SCE support SCE's claim.[325] States are permitted to prevent sales to in-state entities based on potential in-state environmental effects.[326] Indeed, the Supreme Court held that it was not a violation of the dormant Commerce Clause for the City of Detroit to condition access to its port by requiring compliance with local environmental regulations.[327]

An out-of-state company can still decide whether to sell electricity to the California LSEs under the EPS (e.g., by utilizing powerplants that already comply with the EPS, by retrofitting existing, non-compliant powerplants, by building a new complying powerplant), or by selling into California under contracts of less than five years), or the out-of-state company can choose to sell

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[324] *Comments of Southern California Edison Company on the Proposed Decision*, January 2, 2007, p. 14.

[325] *Comments of Southern California Edison Company on the Proposed Decision*, January 2, 2007, p. 14, fn. 18. The cases relied on by SCE involved mandatory reciprocity agreements (*Hardage* v. *Atkins* (10th Cir. 1980) 619 F.2d 871, 872; *Great Atl. & Pac. Tea Co.* v. *Cottrell* (1976) 424 U.S. 366), a compelled preferences for in-state waste (*Hazardous Waste Treatment Council* v. *South Carolina* (4th Cir. 1991) 945 F.2d 781, 785, 791-92), and a solid waste program that required other states to have adopted "effective" community recycling programs in order to receive waste from them (*National Solid Waste Management Ass'n* v. *Meyer* (7th Cir. 1995) 63 F.3d 652, 654-62). These cases are distinguishable from the EPS which contains no mandatory preferences for in-state goods, no mandatory reciprocity agreements, nor does it require other states to comply with California regulations.

[326] *See Cotto Way Co.* v. *Williams* (8th Cir. 1995) 46 F.3d 790, 794 (Minnesota law banning sale of petroleum-based sweeping compounds in Minnesota was not extraterritorial, because the statute was indifferent to sales in other states.).

[327] *Huron* v. *Detroit*, 362 U.S. at 448.

electricity to utilities in states other than California. The EPS is indifferent to electric sales to entities in other states. Simply because the sales to California LSEs under the EPS may affect the costs or profits of an out-of-state generation company (as well as generators in California), this does not make the regulation extraterritorial.[328] We thus reject CEED's and SCE's arguments, and conclude that the EPS is not an "extraterritorial" regulation.

8.4. Conclusion

For the reasons discussed above, we conclude that the EPS does not: 1) discriminate against interstate commerce, 2) impose excessive burdens on interstate commerce in relation to local benefits, or 3) have an extraterritorial effect. In sum, the EPS is valid under the dormant Commerce Clause. As stated aptly by the Ninth Circuit Court:

> "The constitutional principles underlying the Commerce Clause cannot be read as requiring the State ... to sit idly and wait until potentially irreversible environmental damage has occurred ... before it acts to avoid such consequences."[329]

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[328] *See National Electrical Manufacturers Association* v. *Sorrell* (2d Cir. 2001) 272 F.3d 104, 110-111 (Vermont statute upheld because lamp manufacturers had choice as to putting hazardous waste warning label on all lamps sold nationwide, modifying their production and distribution systems to distinguish sales in Vermont and the other states, or to withdraw from the Vermont market entirely.); *See also Star Scientific* v. *Beales* (4th Cir. 2002) 278 F.3d 339, 356 (Virginia statute imposing a fee only on cigarettes sold within the state upheld, even though it affected prices charged by out-of-state distributors. The Fourth Circuit noted that the statute does not have the practical effect of controlling prices outside of the state.).

[329] *Pacific Northwest Venison Producers* v. *Baker* (9th Cir. 1994) 20 F.3d 1008, 1017, (*Quoting Maine* v. *Taylor,* 477 U.S. at 148.).

9. Consideration of Effects on Reliability and Overall Costs to Electric Customers

SB 1368 directs that we consider "the effects of the standard on system reliability and overall costs to electricity customers" in developing and implementing the EPS.[330] We have done so in several ways. First and foremost, by ensuring that new long-term commitments to baseload generation will only be with facilities that emit no more than the GHG emissions rate of a CCGT, we have designed an interim EPS that will protect electricity customers from reliability problems and high compliance costs in the future. As discussed in today's decision, we have ensured this outcome by designing the EPS as the Legislature intended, namely, as a minimum standard of GHG emissions performance for covered procurements similar to an appliance efficiency standard. As SB 1368 recognizes, the resulting reduction in GHG emissions will mitigate adverse impacts on "the economy, health and environment," thereby reducing overall costs to all Californians, including electricity customers.[331]

In addition, the EPS is designed to capture the largest percentage of impact on GHG emissions without compromising system reliability. This is accomplished by defining covered procurements as new long-term commitments to baseload generation, thereby excluding the types of procurements that the LSE is most likely to need for system reliability requirements, i.e., short-term power purchases, long-term contracts with load-following and peaking generation facilities, or new construction of non-baseload powerplants. This focuses compliance on the types of facilities and commitments over which the LSE has

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[330] § 8341 (d)(6).

[331] § 8341 1(a).

the most discretion and choice, thereby minimizing the costs of compliance to the LSE and its electricity customers. In particular, as discussed in this decision, the definition of covered procurements will not subject the millions of dollars in the LSE's already-built facilities to a standard that is being developed to prevent backsliding in LSE decisions made for future investments. In the event that unforeseen reliability concerns and associated costs arise during implementation of the EPS, we have also provided for Commission review of requests for reliability exemptions on a case-by-case basis. Finally, we note that no showing has been made in this proceeding that new, EPS-compliant procurements will not be available at reasonable costs to ratepayers.

In sum, today's adopted EPS fulfills both the letter and the spirit of SB 1368 by effectively "raising the bar" for the GHG emissions performance of new long-term commitments with baseload generation serving California as we transition to a statewide GHG emissions cap.

10. Comments on Proposed Decision

The Proposed Decision of Assigned Commissioner Michael R. Peevey and ALJ Meg Gottstein on this matter was mailed to the parties in accordance with Public Utilities Code Section 311 and Rule 14.2(a) of the Commission's Rules of Practice and Procedure. The following parties filed opening and/or reply comments on the Proposed Decision: AReM, Barclay et al., CCC, CMUA, Calpine, Carson Hydrogen Power Project, CEED, Center for Resource Solutions, the City and County of San Francisco, CE Council, Constellation, DRA EPUC/CAC, Environmental Defense, GPI, IEP, NRDC/TURN/UCS and WRA (filing jointly), Northern California Power Agency, PacifiCorp, PG&E, SCE, SDG&E/SoCalGas, Sierra Pacific and SMUD. We have made corrections and clarifications in many sections of the Proposed Decision in response to these

comments, as well as substantive changes on selected issues, as we describe in today's decision.

11. Assignment of Proceeding

Michael R. Peevey is the Assigned Commissioner and Meg Gottstein is the assigned ALJ in this phase of the proceeding.

Findings of Fact

1. As described in this decision, the Commission has consulted with the California ISO, CARB and CEC during the development of the interim EPS rules.

2. SB 1368 establishes a minimum performance requirement for any baseload generation facility that represents a new long-term financial commitment entered into by entities providing power to California ratepayers. This minimum performance requirement is a GHG emissions performance standard, or "EPS," which limits the powerplant emissions rate to no higher than the emissions rate of a CCGT baseload powerplant.

3. The EPS functions similar to an appliance efficiency standard by ensuring that an LSE does not enter into long-term financial commitments with baseload resources that do not meet a minimum standard of performance.

4. The EPS serves to address the serious adverse consequences of global warming on California's economy, health and environment.

5. The EPS is needed to prevent "backsliding" during California's transition to a statewide load-based GHG emissions cap, that is, to reduce California's exposure to (1) the costs of complying with future laws and regulations that will further limit the emission of GHG gases in the process of generating electricity, and (2) future reliability problems, such as those caused by taking plants out of service to retrofit them (or to retire them early) in order to comply with future laws and regulations limiting GHG emissions.

6. The EPS will help protect Californians from climate change-related phenomena such as: increased number of extremely hot days, air pollution formation, oppressive heat, wildfires, infectious disease vectors, asthma triggers, decreases to the Sierra Nevada snowpack and its derivative effects on California's water supply, diminished electric supply, sea level rise, and the increased occurrence of extreme oceanic events.

7. For the reasons discussed in this decision, current Commission oversight of utility resource planning or the use of a GHG adder in utility procurement does not establish sufficient safeguards against the risks associated with long-term procurement commitments to high-emitting fossil-fueled facilities.

8. SB 1368 directs that the Commission reevaluate and continue, modify or replace the EPS adopted by this decision ("interim EPS") when an enforceable GHG emissions applicable to LSEs limit is established and in operation.

9. There is insufficient data to create and enforce an EPS by the statutory deadline of February 1, 2007 that covers all six of the GHGs.

10. CO_2 is the most pervasive of the GHGs, and the most widely reported and verified of the GHGs at this time.

11. SB 1368 addresses the issue of what entities shall be subject to the EPS by directing that the Commission develop an EPS for LSEs, and by specifically defining that term in the new law.

12. Under SB 1368, the requirement to comply with the EPS is triggered if there is a "long-term financial commitment" by an LSE to baseload generation. For LSE-owned baseload generation, a long-term financial commitment occurs whenever there is a "new ownership investment." For baseload generation procured under contract, there is a long-term financial commitment when the LSE enters into a new or renewed contract with a term of five or more years.

13. SB 1368 defines baseload generation as "electricity generation from a powerplant that is designed and intended to provide electricity at an annual plant capacity factor of at least 60 percent, and defines the terms "powerplant" and "plant capacity factor" for this purpose as follows:

> (a) "Powerplant" means a facility for the generation of electricity, and includes one or more generating units at the same location.
>
> (b) "Plant capacity factor" means the ratio of the electricity produced during a given time period, measured in kilowatthours to the electricity the unit could have produced if it had been operated at its rated capacity during that period, expressed in kilowatthours.

14. A 60% capacity factor captures an estimated 78% of incremental procurement needs in 2012 for PG&E, SDG&E and SCE combined and would capture 72% of CO_2 emissions, based on the data submitted in Phase 1.

15. GPI's recommendation that the EPS be applied to generation from facilities with an annual plant capacity factor of at least 50 percent would establish an interim EPS that is significantly different from the standard intended by the Legislature with the passage of SB 1368.

16. SB 1368 grandfathers CCGT baseload powerplants currently in operation, or that have a CEC final permit decision to operate as of June 30, 2007, as "deemed to be in compliance" with the EPS.

17. Under the provisions of SB 1368, an LSE does not enter into the types of commitments with "retained generation" (i.e., existing baseload facilities owned by the LSE to serve its load) that would trigger the requirement to comply with the EPS, absent additional investment.

18. Constellation et al.'s interpretation of § 8341(d)(1) to mean that the Legislature intended to subject utility-owned retained generation to the EPS,

with or without a "new ownership investment," would contradict the language of §§ 8341(a), (b)(1), (b)(2) and § 8340(j), or render it meaningless.

19. It is doubtful that the "rate recovery contract" with retained generation and kinds of regulatory measures that Constellation et al. describe in their comments are "contracts" as that term is ordinarily understood. Even if they are, they are not the kind of contracts that the Legislature describes in § 8340(j).

20. It is not clear under the proposal made by Constellation et al. how one would determine whether any particular "rate recovery contract" is for a period of less or more than five years.

21. Contracts for the procurement of baseload generation and "contracts" for the recovery of costs associated with generation are two separate things, and we read the plain language of SB 1368 to only apply to the former.

22. In the legislative history of SB 1368, "long-term contract" is consistently referred to in the context of the procurement contracts covered by the Commission's procurement planning process, which do not apply to utility-retained generation.

23. Nothing in the statutory language or legislative history reflects the intent of the Legislature to define a "contract" in the manner suggested by Constellation et al.

24. The definition of covered procurements proposed by Constellation et al. would subject the millions of dollars in the LSE's already-built facilities to a standard that is being developed to prevent backsliding in LSE decisions made for future investments, and to avoid the additional financial and reliability risks that such backsliding would create.

25. SCE's interpretation of "long-term financial commitment" under SB 1368 is that the Legislature intended to limit that commitment to an investment in

baseload generation that is *also* a new ownership interest. In effect, under SCE's interpretation, the EPS would never be triggered for new investments made by the LSE to its retained generation.

26. SCE's assertion that the absence of a comma in the phrase "new ownership investment" mandates their reading is incorrect based on the rules of grammar described in several sources of grammatical usage. According to those sources, a comma would only be necessary if one could substitute the phrase "ownership, new investment" for the phrase "new, ownership investment" without affecting the meaning, which is not the case for the phrase "new ownership investment." These authorities also establish that no comma is required for this phrase, since the first adjective ("new") modifies the idea expressed by the combination of the second adjective and the noun ("ownership investment").

27. As discussed in this decision, SCE's reading of § 8341(b)(6) in support of its interpretation is contrary to the plain meaning of the statute, which explicitly prohibits LSE's from entering into long-term commitments that fail to comply with the EPS.

28. We conclude from the legislative history that the Legislature added "new" to preclude the broader interpretation that would include all utility retained generation and not, as SCE contends, to exclude new investments in utility retained generation.

29. SB 1368 does not specify what types of new investments made by an LSE in retained generation would trigger the EPS.

30. The Senate Floor Analysis for SB 1368 states that "the purpose of this bill is to prevent long-term investment in powerplants with GHG emissions in excess of those produced by a combined-cycle natural gas power plant."

31. Requiring that every replacement of equipment or addition of pollution control equipment would trigger compliance with the EPS does not recognize that the plant and its operation may remain essentially unchanged and such alternations may not even increase the level of expected emissions from the facility over the long-term. More importantly, this approach could reduce powerplant reliability as old parts are repaired rather than replaced.

32. Setting a dollar level threshold to trigger EPS compliance for new ownership investments, as some parties suggest in their comments, would be an arbitrary exercise.

33. Defining the EPS trigger to include LSE investments in retained generation intended to (1) extend the life of one or more units of an existing busload powerplant for five years or more, or (2) that result in a net increase in the existing rated capacity of that powerplant, or (3) is designed and intended to convert a non-baseload plant to a baseload plant, is a workable definition that is consistent with the objectives of SB 1368.

34. Defining the EPS trigger in this manner covers "repowering" as the term is generally used in the industry, which is the type of investment in retained generation that staff and most parties agree should be included under the definition of new ownership investments.

35. The fact that more than one generating unit happen to be at the same location should not be a "sufficient" condition for treating them as a single powerplant, because doing so could lead to the absurd results described in this decision. These include encouraging the co-location of renewables or other low-emitting generating units with units that emit very high GHG emissions, or co-locating generating units designed and intended to operate at capacity factors much lower than 60% with those designed and intended to operate as baseload

generation (60% or greater capacity factor), in order to circumvent the EPS rules. Clarification of the circumstances under which a "powerplant" is a facility comprised of more than one generating unit will avoid the absurd results described in this decision, and improve the implementation and enforcement of the EPS.

36. Based on the common definition of the verb "deem," a CCGT powerplant that is *deemed* compliant does not have to demonstrate actual compliance with the adopted EPS standard, but is instead treated *as if* it met the EPS standard and is excused from making an affirmative showing of compliance.

37. The staff proposal would essentially apply the same standard of review for deemed compliant CCGT plants as for all other existing plants.

38. There is no indication in SB 1368, or in its legislative history, that the Legislature intended that CCGT powerplants, or any of the individual CCGT units such powerplants contain at the time they are deemed compliant, should lose their deemed-compliant status solely due to contract renewal.

39. Reading § 8341(d)(1) to require that the same kind and scale of alterations, improvements, additions, or renovations that constitute "new ownership investment" would also trigger a requirement that deemed-compliant CCGT powerplants demonstrate actual compliance with the EPS, would render the § 8341(d)(1) deemed-compliant provision redundant as applied to utility-owned CCGT powerplants.

40. In order to give §§ 8340(j), 8341 and 8341(d)(1) their full effect with respect to utility-owned CCGTs in operation as of the date of implementation of the EPS (or that obtain a CEC permit as of June 30, 2007), it is reasonable to interpret SB 1368 to mean that "new ownership investment" in retained

generation does not automatically trigger EPS review for deemed-compliant CCGT powerplants.

41. Interpreting SB 1368 to mean that existing CCGT are deemed to be permanently in compliance regardless of any subsequent changes to the facilities, however, would lead to absurd results, e.g., it would allow an LSE or non-LSE owner to circumvent the EPS simply by co-locating additional units with existing units within a previously deemed-compliant CCGT powerplant.

42. The deemed-compliant status is given to existing CCGT plants, and extending the exemption to units that did not exist at the time of the passage of the statute is contrary to the purpose and the intent of the law.

43. To give meaning to each section of the statute and avoid absurd results, it is reasonable to require EPS compliance when units are added to a deemed-compliant CCGT powerplant that result in a significant increase to the powerplant's rated capacity.

44. Establishing a 50 MW threshold for this purpose recognizes that Public Resources Code § 25123 establishes a 50 MW threshold to demarcate the boundary between significant and minor changes in generating capacity for the purpose of triggering CEC powerplant permitting requirements.

45. Limiting our reading of what parts of a CCGT powerplant are deemed compliant (to exclude additional units totaling 50 MW or more) avoids redundancy and gives each word of § 8341(d)(1) a legal effect distinct from the other provisions of the statute.

46. Nothing in today's decision or SB 1368 limits the Commission's existing authority to require that utility-owned, or contracted for, CCGT powerplants are properly maintained and are operated as cleanly and efficiently as possible.

47. For EPS purposes the "term" of a contract should be defined as "the date of first delivery through the date of last delivery (even if there are intervening periods during which there are no deliveries)."

48. SB 1368 directs the Commission to establish an EPS at a rate of emissions of GHGs that is "no higher" than the emissions rate of a CCGT powerplant, but does not specify the emissions rate for a CCGT.

49. SDG&E/SoCalGas interpret SB 1368 to mean that the Legislature intended for all deemed-compliant CCGTs to be able to demonstrate that they would pass the adopted standard, if they were required to do so.

50. Our reading of SB 1368, in conjunction with the common definition of the verb "deem," indicates that the Legislature intended to allow the Commission to adopt a standard that some deemed-compliant CCGT powerplants might not be capable of meeting.

51. Had the Legislature intended for the EPS to reflect the GHG emissions rate associated with gas-fired units, not just CCGTs, it would have stated so explicitly.

52. In selecting CCGT technology as the basis for the EPS, we must assume that the Legislature recognized that this technology is considered to be the technology of choice for new baseload power generation fired by natural gas due to its efficiency advantages over other forms of gas-fired power generation.

53. SB 1368 specifically directs that the EPS emissions rate be reflective of a baseload CCGT, and not intermediate/shaping gas-fired units, as some parties suggest in their comments.

54. An EPS performance level of 1,100 lbs of CO_2 per MWh is above the weighted average of 2004-2005 data of emissions rates associated with a broad range of CCGT powerplants of varying vintages, but lower than the emissions

rates associated with the oldest, most inefficient "deemed compliant" CCGT powerplants still in operation.

55. In Resolution E-3940, this Commission found that a 1.5% increase in the heat rate is a reasonable estimate for the impact of dry cooling on the heat rate of the RPS-referent CCGT baseload powerplant.

56. All other things being equal, CCGT powerplants located in a desert (high ambient temperature) or high altitude areas will have higher heat rates (and higher GHG emissions) than those located in the coastal regions of California.

57. Based on the record in this proceeding, an EPS emissions rate of 1,100 lbs of CO_2 per MWh is consistent with the intent of the Legislature to base the EPS on CCGT emissions rates, and also reasonably accounts for potential CCGT plant "outliers" from the average data on CCGT emissions rates to accommodate those units that utilize dry cooling technologies, are smaller-sized facilities or are located in the desert or at high altitudes.

58. At the same time, an EPS emissions rate of 1,100 lbs of CO_2 per MWh avoids establishing a standard that is representative of the most inefficient, older CCGT powerplants in operation, which is appropriate in light of the statute's grandfathering provisions. Those provisions reflect the Legislature's concern that some of the older, less efficient CCGT powerplants in operation would not be able to meet the standard.

59. It is the characteristics of the powerplant(s) underlying new long-term contractual commitments that create the potential financial risk to California consumers and exposure to future reliability problems that this Commission and the Legislature seek to reduce through the establishment of an EPS.

60. Accomplishing the goals of SB 1368 and this Commission's GHG reduction policies requires looking at the characteristics and emissions of the

powerplant(s) being contracted for, *not* just the characteristics of the contracted-for deliveries, as some parties propose.

61. Interpreting the "supplied under" language of §§ 8341(a),(b)(1) and (3) as permitting us to assess the applicability of the EPS based only on the energy made available under contract to the LSE, rather than on the operations of the underlying powerplant, would :

(a) Render useless the language of §§ 8341(4) that states:

"In determining whether a long-term financial commitment is for baseload generation, the commission ***shall consider the design of the powerplant and the intended use of the powerplant..."*** (Emphasis added.)

(b) Ignore that "supplied under" in all instances where it appears in SB 1368 follows the term "baseload generation," which is defined under § 8340(a) in terms of "*electricity from a powerplant* that is designed and intended to provide electricity at an annualized plant capacity factor of at least 60%." (emphasis added), and similarly,

(c) Ignore that the term "plant capacity factor" is also defined by § 8340(1) in reference to the underlying plant operations.

62. Customer generators that sell power to the LSE under long-term contract (i.e., contracts with a term of five years or greater) still represent a resource upon which the LSE relies, even if the amount of energy delivered to the grid is small.

63. Application of the EPS should avoid situations where the LSE makes separate arrangements for high GHG-emitting resources that also generate power for on-site load, since the same risks of high costs and reliability problems in the future apply to those facilities.

64. Applying the EPS to the characteristics of the underlying facility or facilities supplying power under contract to the LSE, irrespective of whether those facilities are operated by a customer generator or by a merchant generator, ensures that LSEs do not enter into long-term contract commitments with

powerplants designed and intended for baseload operations with GHG emissions higher than CCGT powerplants. As discussed in this decision, the treatment of the powerplants under EPUC/CAC's example is consistent with this purpose, and does not create a "possible discrimination" between customer-owned generation and merchant generation.

65. By law, the EPS governs the long-term financial commitments of LSEs to any baseload generation, and SB 1368 directs this Commission to design and implement an EPS for this purpose.

66. Once a customer generator decides to offer power over and above its own (or over the fence) on-site consumption to an LSE under a contract of five years or more, the power supplied comes under Commission purview for the purposes of evaluating the LSE's (not the customer generator's) compliance with the EPS.

67. Staff's proposed treatment of partial contracts would exempt partial year contracts from the EPS if the contracted-for hours of energy delivery under the contract represent less than 60% of the total number of hours in the year. In effect, this represents a blanket exemption for seasonal procurements, even if the underlying facility generating the summer product is a baseload generation facility as defined under SB 1368.

68. Considering the expected capacity factor of the contractual commitment (not the underlying powerplant(s)) for partial-year contracts is inconsistent with the application of the EPS to all other contract commitments under the adopted EPS, and would create a significant loophole in EPS compliance.

69. Staff's proposed treatment of partial contracts is not necessary to address potential seasonal reliability concerns. To the extent that such concerns arise from the application of an EPS that applies only to long-term contractual commitments with baseload facilities, LSEs may request a reliability exemption

on a case-by-case basis, as provided for by this decision. There is no compelling reason to create a blanket exemption for this purpose.

70. Staff's and GPI's proposal for firmed renewable products applies the EPS from the viewpoint of contract deliveries, i.e., by applying the EPS on a blended basis to the contracted-for deliveries from the renewable and non-renewable resources underlying that product. In general practice, this means that the procurement would be automatically exempt from the EPS as long as less than half of the deliveries are from the non-renewable firming resource.

71. PG&E's proposed treatment of firmed renewable products would exempt all firmed renewable product from the EPS, irrespective of the emissions profile of the underlying non-renewable firming resource or the level of deliveries from that contract.

72. The proposed treatment of firmed renewable products presented by staff, GPI and PG&E is inconsistent with the direction of SB 1368 that EPS compliance be based on the underlying facility or facilities producing power, not just the delivered product under a contract.

73. Nothing in the language of SB 1368 or its legislative history indicates that the Legislature intended to carve out an exception for firmed renewable products.

74. The proposal of NRDC, TURN, UCS, WRA and DRA to apply the EPS to each facility underlying a contract, including one for a firmed renewable product, is consistent with the plain language of SB 1368.

75. PG&E's argument that SB 1368 permits a small facility or contract size exemption violates a basic rule of statutory construction by ignoring the "any" and "all" language of §§ 8341(a) and 8341(d)(1).

76. We cannot reconcile PG&E's recommendation for a small size exemption with the plain language of SB 1368.

77. The legislative history of SB 1368 provides no indication that the Legislature ever considered including a blanket exemption for facilities or commitments under a certain size.

78. Any selection of a size threshold for such an exemption would be an arbitrary one, and could have the unintended consequences of driving down the size of high-emitting facilities for the sole purpose of obtaining an exemption from the EPS.

79. A blanket exemption for small utilities (less than 75,000 retail customers) is not provided under § 8341(d)(9) as CEED suggests, but rather, that section of the statute states that the Commission may accept proposals for alternate compliance from multi-jurisdictional utilities under specific circumstances. Moreover, a blanket exemption for all utilities with less than 75,000 customers would not achieve the same level of emissions reductions and associated reduction in future risks and costs intended by the Legislature.

80. SB 1368 provides the flexibility to both encourage new technologies while meeting the EPS standard. In particular, SB 1368 directs the Commission to: (1) calculate emissions rates based on "net emissions" from the production of electricity and (2) not to count CO_2 that is injected in geological formations as emissions of the powerplant in determining compliance with the EPS. However, neither the plain language of SB 1368 nor the legislative history indicates that the Legislature contemplated the type of RD&D exemption proposed by staff when drafting the statute.

81. Calculating the emissions rate of powerplants with sequestration projects contemplated under § 8341(d)(5) based on the net emissions over the life of the

powerplant recognizes that a CO_2 injection project may not be operational until after the powerplant comes on-line or the LSE enters into the contract.

82. Implementing §§ 8341(d)(2) and (5) to require EPS compliance based on reasonably projected net emissions over the life of the facility serves the purposes of SB 1368.

83. Small power production facilities that use solar thermal electric, wind, geothermal or certain biomass technologies are pre-approved as compliant under this decision.

84. Other small power production QFs, such as hydroelectric facilities, may very well be able to meet the EPS.

85. The cogeneration efficiencies of QFs are accounted for in calculating the emissions rates for cogenerators, thereby assisting cogenerators in meeting the EPS.

86. EPUC/CAC's recommendation that all existing gas-fired cogeneration should be deemed to be in compliance with the EPS is inconsistent with the plain language of SB 1368, including § 8341(d)(3) directions on how the emissions for cogeneration facilities should be calculated in demonstrating EPS compliance.

87. Both topping and bottoming-cycle cogeneration generate electricity. Bottoming cycle cogeneration generates electricity using waste heat from an industrial process, whereas topping cycle cogeneration does the reverse: It utilizes the waste heat from the generation of electricity.

88. ECAC/CAC's assertion that bottoming-cycle cogeneration is not a powerplant does not comport with the SB 1368 definition of powerplant as a "facility for the generation of electricity."

89. SB 1368 does not distinguish between topping and bottoming-cycle cogeneration in the application of the EPS.

90. EPUC/CAC provide no evidence for their assertion that there are no emissions associated with the production of electricity using bottoming-cycle cogeneration technologies.

91. EPUC/CAC acknowledge, in fact, that when supplemental firing is used to enhance the performance of bottoming cycle facilities, any resulting emissions attributable to the supplemental firing may need to be considered in developing an emissions rate for the cogeneration facility.

92. By limiting the application of the EPS to long-term commitments, rather than short-term transactions, and to baseload powerplants, rather than to those designed to be used for load shaping or peaking, the adopted EPS protects California ratepayers from long-term reliability risks while minimizing potential adverse impacts on short-term reliability and associated costs.

93. Applying the interim EPS on a gateway basis also provides LSEs with the flexibility to operate their facilities differently than originally designed or intended in order to address unanticipated short-term reliability needs.

94. A reliability exemption will probably not be needed given the definition of covered procurements and other design aspects of the interim EPS. Nonetheless, allowing for the possibility of granting this limited exemption, on a case-by-case basis, addresses concerns that unexpected reliability problems may arise during EPS implementation.

95. A reliability exemption is workable to implement, since a specific reliability concern and associated costs may be readily assessed as the "go, no-go" decision is being made for each new long-term financial commitment with baseload generation.

96. In contrast, in the context of an EPS no single procurement can be said to cause significant cost or economic impacts, in and of itself, for a utility's

customer. This is because by its very nature and purpose, and similar to an appliance efficiency standard, the EPS requires that each determination be made without respect to whatever set of energy procurement opportunities a given LSE has available.

97. No party proposing cost-based exemptions or cost containment measures provides any evidence that the costs to ratepayers of procuring EPS-compliant resources will be unreasonable, or considers the economic, health and environmental benefits associated with the EPS in arguing that such proposals are warranted.

98. Price caps in the context of an EPS could mean that a long-term commitment to an otherwise non-compliant plant should nevertheless get a "go" rather than a "no go" because the cost of reducing GHG emissions for that particular plant would exceed more than $s/ton. Or, as in the case of the Massachusetts, Oregon and Washington price cap policies mentioned by CEED, the long-term commitment should be allowed because the LSE can pay $x/ton to a qualifying organization (e.g., the Massachusetts GHG Expendable Trust) for each ton above the standard.

99. Either way, price caps would allow the LSE to build or enter into long-term contracts with high GHG-emitting plants without any reduction in those plants' emissions. This would undermine the SB 1368 goal of protecting ratepayers from the risks of entering into long-term commitments to high GHG-emitting baseload facilities in the first place.

100. No party has addressed how such a price cap could realistically be established by the statutory deadline of February 1, 2007.

101. It is reasonable to make some provision in our rules for "extraordinary circumstances, catastrophic events, or threat of significant financial harm" that may arise during EPS implementation due to unforeseen circumstances.

102. SB 1368 requires the Commission to adopt a methodology for calculating the emissions rate associated with cogeneration facilities that recognizes both the thermal and electrical output associated with cogeneration.

103. The Heat Rate of the Generator Method for calculating the emissions rate of cogeneration does not recognize that the thermal output (from the primary electric generation process) at a cogeneration facility will most likely be used directly as steam to do work, not converted into electricity in a secondary electric generation process that would incur the thermodynamic losses at the heat rate of the generator.

104. Using an electric heat rate to convert thermal energy output to kWh in this manner can double count the efficiency losses in the context of an output-based methodology.

105. The Avoided Emissions Method is problematic because it can be very difficult to determine the characteristics of the stand-alone boiler whose GHG emissions are avoided by a cogenerator. As a result, future power contract negotiations could end up being extremely complex and contentious over this issue.

106. The record in this proceeding does not provide us with a reasonable approach for estimating the emissions from the boiler that would be utilized in the absence of cogeneration. SDG&E/SoCalGas' assumption of 80% efficiency for such a boiler is an arbitrary selection.

107. The CEC data that SDG&E/SoCalGas suggest could instead be used to determine the general efficiency of gas boilers may not be representative of

boilers located outside of California and, in any event, it would be inaccurate to assume that general efficiency for all boilers since not all cogeneration facilities are gas-fired.

108. Cogeneration facilities under consideration are not necessarily new facilities. Therefore, it would be inaccurate to assume that the boiler used in its place would have efficiencies that meet current standards, as SDG&E/SoCalGas suggest as an alternative.

109. A comparison of the Avoided Emissions Method with the Conversion Method also reveals that the Avoided Emissions Method may effectively ignore important fuel savings benefits associated with cogeneration. This appears to be due, in large part, to the fact that the Avoided Emissions Method uses two different resources to produce two different products (electricity and steam), whereas cogeneration uses one process that captures the benefit of two products. As a result, the Avoided Emissions Method may calculate an emissions rate based on the use of more fuel than a cogeneration facility might otherwise use during its actual operation.

110. In contrast to the Heat Rate of the Generator Method, the Conversion Method represents an output-based method that appropriately recognizes that the thermal output of a cogeneration facility can be used directly as steam to do work, and not for the secondary production of electricity.

111. Relative to the Avoided Emissions Method, the Conversion Method has the advantage of being (1) more accurate in calculating the actual emissions rate of the cogeneration facility, since it takes into account the actual thermal output of the cogeneration facility, (2) easier to implement and administer because it does not involve making assumptions about the type of boiler "avoided" and

associated emissions rates. In addition, the Conversion Method fully recognizes the fuel savings benefits associated with cogeneration.

112. The emissions and cogeneration credit calculations presented in Attachment 5 are currently shown as though the facility operates as a topping-cycle facility. These calculations can readily be shown for a bottom-cycle facility by: (1) showing the thermal output first, followed by the electric output in Tables A, B and C and (2) rearranging Table D so that thermal output precedes electric output.

113. EPUC/CAC's proposal in their comments on the Proposed Decision on how to calculate the emissions from bottoming-cycle cogeneration should be rejected because it produces a formula that counts the energy input for only one of the co-generation outputs, but divides by both outputs to produce the resulting emissions rate.

114. The FERC definition of "useful thermal energy" in its regulations mandating the minimum efficiencies of a QF recognizes that there are losses from converting available thermal energy into "useful work," and that some of the available thermal output may be wasted (not "used") by the thermal host.

115. Using the existing documentation requirements of cogeneration facilities, as described in this decision, represents a reasonable and workable way to document the useful thermal energy output and other values for the Conversion Method formula of cogeneration facilities at EPS gateway screen.

116. Based on our reading of SB 1368, we are not precluded from making an upfront one-time determination of EPS compliance for renewables based on our consideration of representative emissions rates.

117. It would be redundant and costly to require that LSEs demonstrate EPS compliance for each new ownership investment, new contract or renewed

contract with baseload renewable resources if the record clearly demonstrates that these resources comply with the EPS on a net emissions basis.

118. The record in Phase 1 demonstrates that the net GHG emissions produced from the renewable resources and technologies listed below are either zero, significantly less than the EPS or even result in a net reduction in GHG emissions (in the case of biomass):

(a) Solar Thermal Electric (with up to 25% gas heat input)

(b) Wind

(c) Geothermal, with or without reinjection

(d) Generating facilities (e.g., agricultural and wood waste, landfill gas) using biomass that would otherwise be disposed of utilizing open burning, forest accumulation, landfill (uncontrolled, gas collection with flare, gas collection with engine), spreading or composting.

119. The usual disposal options for biomass wastes emit large quantities of methane gas, which is on the order of twenty to twenty-five times more potent as a GHG than CO_2.

120. Electric production alternatives either burn the wastes that would become methane gas or burn the methane gas itself, generating CO_2.

121. Electricity production using biomass that would otherwise be disposed of under a variety of conventional methods (such as open burning, forest accumulation, landfills, composting) results in a substantial net reduction in GHG emissions.

122. It would not be reasonable for us to make a blanket determination today that *all* renewable resources or technologies are EPS-compliant, however, since the evaluation of net emissions presented on the record and discussed in parties' comments did not consider any other types of renewable resources or technologies (e.g., hydroelectric, fuel cells, photovoltaics, biodiesel, and ocean

thermal systems), or biomass generating projects where growing the fuel is required.

123. The issue of how to treat RECs or "null renewable power" (renewable resources that have sold off their RECs) in the context of EPS compliance should be addressed even though there is no tradable regulatory REC market in California at this time. Deferring the issue would introduce considerable uncertainty with respect to the treatment of renewables and create a potentially dampening effect on the development of these resources.

124. In the context of an RPS program, the REC that is sold carries with it all the renewable attributes associated with the production of electricity so that another entity (LSE) can apply those attributes to meet its RPS obligation, which is also defined in terms of electricity production.

125. In the context of EPS compliance, however, stripping renewables of their emission profiles when RECs are sold could easily create a "perverse" result; namely, it could discourage new long-term commitments with baseload renewable generators that have zero, low or even negative net GHG emission profiles in favor of facilities with higher GHG emission profiles.

126. As long as RECs cannot be used to offset emissions for the "go, no-go" EPS-compliance determination, looking at the actual nature of the underlying plant even if RECs are sold does not create a double counting problem. Moreover, such treatment is not inconsistent with § 399.12, as amended by SB 107, which provides that a REC "includes all renewable and environmental attributes associated with the *production* of electricity" (emphasis added), not discrete investment decisions.

127. As discussed in this decision, stripping renewables of their emissions attributes in the context of EPS compliance could result in the emissions from

two identical renewable baseload generators that sell off their RECs being valued very differently, depending upon who owns the generator.

128. Stripping renewables of their emissions attributes with the sale of RECs requires imputing emission factors to the resulting null renewable power, for which we lack a reasonable method at this time.

129. SB 1368 directs this Commission to address long-term purchases of electricity from unspecified sources (or "unspecified contracts") in a manner consistent with the statute.

130. By requiring that the Commission "address" the matter of unspecified contracts, SB 1368 does not require any particular outcome and defers the matter to the Commission's discretion.

131. In order to comply with SB 1368's mandate that we address unspecified sources in a manner consistent with the rest of the statute we must ensure that:

(1) LSEs only enter into long-term financial commitments with baseload generation that comply with the EPS, and

(2) EPS compliance cannot be achieved in a manner that would yield a contrary result, i.e., that results in an increase in long-term commitments with high-emitting sources.

132. The concept of imputing emissions rates with the requirements of SB 1368 is difficult to reconcile with the requirements of SB 1368 since, by definition, such proxies do not reflect the actual emissions from a resource. As a result, using imputed emissions rates does not permit one to determine whether a commitment with an unspecified resource is consistent with SB 1368 or simply exacerbates the problems this Commission and the Legislature are trying to address.

133. Any method to impute a GHG emissions rate to unspecified resources results in a binary outcome in the context of an EPS—that is, all financial

commitments with unspecified resources will either "pass" or "fail" based on the selected level of imputed emissions. This results in enormous pressure to game the methodology and input assumptions used for this purpose, thereby making it very difficult and contentious to implement this particular approach to addressing unspecified contracts.

134. As illustrated in comments in this proceeding, various input assumptions associated with calculating an imputed emissions value using the California Net Power Mix, as well as other proxies for the resource mix, can be manipulated to "push" an unspecified contract through the EPS.

135. SCE's recommendation for the treatment of unspecified contracts also has the potential to push an unspecified contract through the EPS gateway, since the proposed default rates are based on broad regional averages that would permit high emitting resources to pass through the EPS screen.

136. Under SCE's proposal, the case-by-case review would be one-sided: The Commission would be asked to grant an exception to the imputed emissions value only in those instances where the power is being purchased from a group of very low emitting resources (e.g., a group of all hydroelectric powerplants), but not when the opposite may be true.

137. The WECC system average is generally not reflective of California activities or markets.

138. The use of WECC sub-regional geographic averages, including SCE's proposed alternative of using the WECC California region average carbon intensity factor, represent broad emissions averages that would dilute the impact of high-emitting resources and potentially allow them all to automatically pass through the EPS screen.

139. The California Net Power Mix is a calculation based on what is left over after the amounts that retailers voluntarily report as the resources underlying their short- and long-term power purchases (and accounting for on-site generation). It was developed by the CEC for power content labeling, and has not been revised, updated or endorsed by the CEC for use in inputting GHG emissions under SB 1368 or in any other GHG policy context.

140. There is no clear conceptual link between the California Net Power Mix and the mix of resources that might underlie unspecified contracts now or in the future, even on a system-wide basis.

141. Requiring all long-term commitments for baseload generation be made with "specified resources" that can demonstrate compliance with the interim EPS ensures that "any" and "all" long-term financial commitments with baseload generation will meet the EPS, as SB 1368 so directs. Moreover, this approach cannot be gamed in a manner that could result in the opposite outcome than the statute intended, i.e., an increasing number of long-term commitments to high emitting resources.

142. SCE, SDG&E and PG&E did not enter into any contracts of five years or more for unspecified resources in 2004 and 2005 and state that they do not anticipate entering into any contracts with unspecified resources with a term of five years or more during the 2006-2008 procurement period.

143. Based on the record in this proceeding, it appears highly unlikely that LSEs will be entering into any new or renewal contracts of five years or greater that are unspecified during the transition to a statewide GHG emissions limit.

144. Requiring that all long-term contracts with baseload generation be "specified" in order to demonstrate EPS compliance should not have a significant, if any, impact on an LSE's resource procurement flexibility.

145. "Specified" contracts (or "specified resources") identify the powerplant(s) that will be delivering power under the contract, but the following circumstances would also comply with the EPS rules: First, if the long-term contract specifies that power will be delivered exclusively from pre-approved renewable technologies or resources, and there are assurances in the contract to that effect, then the contract would comply with the EPS even if none of the generating sources are specified. Second, if a group of powerplants from which power will be delivered under a contract is specified, and there are assurances in the contract that deliveries will only be from one or more of the powerplants in that group *and* each of those that are baseload powerplants would individually pass the EPS, then the contract would comply with the EPS. The burden should be on the LSE to provide sufficient documentation to demonstrate compliance with the EPS under these circumstances.

146. The ISO relies on specific information about the plant facility and its location in making system reliability determinations within the ISO control area; therefore, the requirement to specify the resources underlying long-term contracts for the purpose of demonstrating EPS compliance is consistent with the type of information that the ISO also requires for these reliability determinations.

147. A requirement that long-term power purchase contracts specify the underlying generation facilities for EPS compliance is consistent with our discussion of emissions registration in D.06-02-032 and represents a logical interim step towards the implementation of the statewide emissions cap under AB 32.

148. Permitting LSEs to enter into new or renewed long-term unspecified contracts with high GHG-emitting facilities through the use of an imputed emissions value for system power could put them, and their customers, in a

vulnerable position when the AB 32 reporting requirements take effect in 2008 for the implementation of the statewide, load-based GHG emissions limits.

149. The record indicates that it is entirely feasible to implement a program that tracks the GHG emissions of all generating units, and that would enable marketers and other sellers of unspecified resource contracts to assign a reasonable and accurate GHG emissions profile to their contracts. As discussed in this decision, specific tagging mechanisms have been developed in other jurisdictions to track generation attributes, including GHG emissions. While LSEs have stated that they are not likely to pursue long-term unspecified contracts as a general rule, the record in this proceeding indicates that they do intend to continue negotiating long-term contracts with specified resources that contain "substitute energy provisions," i.e., provisions that permit the seller to substitute system energy on a short-term basis as needed for operational or efficiency reasons.

150. Substitute energy provisions in long-term contracts can provide greater performance assurance at more moderate price to ratepayers, and appropriate restrictions to their usage can be put in place to guard against the intentional sourcing of energy from high carbon-intensive baseload resources.

151. PG&E's proposal appropriately restricts substitute system energy purchases under long-term contracts in the context of dispatchable resources by limiting such purchases to no more than 15% of forecasted output of the specified powerplant and restricting the use of substitute system energy purchases to unpredictable events or circumstances, such as forced outages.

152. However, PG&E's proposal does not adequately recognize the unique characteristics of intermittent renewable resources (wind, solar, run-of-river

hydroelectricity), where both increments and decrements to the level of system energy are associated with firming such resources.

153. One way to recognize these unique characteristics is to limit the purchases of substitute system energy purchases such that total purchases under the contract (whether from the intermittent renewable resource or from substitute unspecified sources) does not exceed the total expected output of the specified renewable powerplant. Under this approach, one can expect the increments and decrements in system energy purchases to average to zero on balance.

154. Limiting substitute energy purchases in this manner provides the type of contracting flexibility and practicality that is uniquely required for long-term contracts with specified intermittent renewable resources, without creating a loophole or exception to the general rule on unspecified contracts that would be contrary to the intent of SB 1368.

155. Permitting substitute system energy purchases under long-term contracts with intermittent renewable resources to equal far more than the expected output of the intermittent renewable resource (e.g., 80% of rated capacity for a wind generator) would result in increments to unspecified system energy purchases that can be expected to significantly and regularly exceed the decrements to system power over the life of the contract. As a result, this approach has the potential to create a significant loophole to the general rule for unspecified contracts that would permit LSEs to enter into long-term contracts with high-emitting resources, yielding a result that is contrary to the intent of SB 1368.

156. A gateway screen approach for demonstrating compliance with the interim EPS is consistent with the intent of SB 1368, which directs us to look to the "design and the intended use" of the powerplant under § 8340(a).

157. A gateway screen approach is the most practicable and enforceable manner in which to determine EPS compliance.

158. As discussed in this decision, EPS compliance submittals can be readily incorporated into existing Commission procedures for LSEs that currently file their procurement plans and contracts for Commission pre-approval; namely, for SCE, PG&E and SDG&E.

159. New procedural vehicles need to be established for LSEs that are not currently required to submit procurement plans or apply for Commission pre-approval of procurement contracts, that is, for community choice aggregators, electric service providers and the small electrical corporations" (those other than PG&E, SCE and SDG&E).

160. Permitting small electrical corporations, electric service providers and community choice aggregators to submit an after-the-fact EPS compliance showing avoids creating new pre-approval requirements and associated administrative complexity for the Commission's regulation of the procurement practices of these entities.

161. Permitting small electrical corporations, electric service providers and community choice aggregators to file an after-the-fact compliance submittal for EPS compliance is consistent with other procurement-related compliance procedures we have established for electric service providers and community choice aggregators.

162. The documentation and other requirements adopted in this decision provide reasonable safeguards against the risks to ratepayers of potential non-compliance by an LSE that files an after-the-fact compliance showing.

163. For the reasons discussed in this decision, the resource adequacy filing submitted by these entities is not the appropriate procedural vehicle for documenting after-the-fact EPS compliance.

164. An annual Attestation Letter, filed as an advice letter with opportunity for response/protest, is a reasonable procedural vehicle for community choice aggregators, electric service providers and small electrical corporations to use for documenting after-the-fact compliance with the interim EPS standard.

165. As discussed in this decision, an electric service provider, community choice aggregator or small electrical corporation should also be permitted to file an Advice Letter requesting Commission pre-approval of a new financial commitment as EPS compliant.

166. Under SB 1368, the Commission may consider a showing of "alternate compliance" by multi-jurisdictional electrical corporations that serve 75,000 or fewer retail end-use customers in California pursuant to § 8341(d)(9).

167. The two multi-jurisdictional utilities subject to SB 1368, Sierra Pacific and PacifiCorp seek alternative compliance with the EPS.

168. There is no compelling reason to defer our decision to consider what constitutes a showing of alternative compliance.

169. PacifiCorp's three alternative compliance tests to determine what qualifies as "review" closely track the statutory language and appear consistent with staff's final recommendations.

170. Both PacifiCorp and Sierra Pacific serve fewer than 75,000 customers within California, and are required to disclose GHG emissions related to

procurement to another state's utility regulatory commission, and therefore meet the alternative compliance requirement.

171. The EPS serves a fundamentally different purpose, reflecting different policy objectives, than programs to reduce GHG emissions through a portfolio-wide cap, cap-and-trade programs or programs that permit LSEs to create or purchase offsets to meet an emissions cap or performance standard. As discussed in this decision, the purpose of these programs is to provide varying degrees of compliance flexibility when the primary policy goal is to reduce the overall level of emissions generated through procurement activities.

172. The purpose and objective of the interim EPS (i.e., to ensure that the LSE does not enter into long-term financial commitments with high-emitting baseload resources in the first place) cannot be accomplished if LSEs are permitted to comply with the standard by diluting the emissions from high-emitting powerplants through portfolio averaging, or by increasing the permissible level of emissions for non-compliant powerplants through offsets or other means.

173. Portfolio averaging or increasing the permissible level of emissions for non-compliant powerplants through offsets or other means would only disguise the types of problems that the EPS is designed to avoid, e.g., the high costs of future plant retrofits and reliability disruptions as it becomes increasingly difficult for these high-emitting facilities to comply with GHG emission regulations.

174. A workable offsets program cannot be designed and implemented within the timeframe contemplated for an interim EPS, particularly in light of the SB 1368 statutory requirement that an enforceable EPS be put in place no later than February 1, 2007.

175. The documentation required by this decision will provide this Commission and Commission staff with information necessary to review EPS compliance, either in pre-approval requests or in reviewing after-the-fact Attestation Letters.

176. Disclosure of LSE investments in retained generation, including "deemed-compliant" CCGTs is necessary to monitor compliance with the adopted EPS rules.

177. Consistent with the guidance in § 8341(b)(4), LSEs should present documentation that relates to establishing the design and intended use of the powerplant.

178. LSEs should provide documentation of capacity factors, heat rates and corresponding emissions rates that reflect the actual, expected operations of the plant.

179. The full load heat rate is the heat rate of a plant at full output and is not representative of the actual operations of a plant.

180. As discussed in this decision, using the International Organization for Standardization measurement standards may not provide appropriate documentation for the purpose of demonstrating EPS compliance, particularly for those powerplants located in high temperature or high altitude regions. Therefore, it would not be reasonable to require all LSEs to use these standards.

181. For the purpose of determining the "term" of a contract under these EPS rules, two or more contracts, including contractual options, should be treated as one ("linked") under certain circumstances.

182. The concept of linkage needs to be spelled out in detail now, so that the LSEs can comply with the EPS.

183. SCE suggested that contracts be considered "linked" in either of the following situations: "(1) the contracts specify the same generating unit as the primary source and the gap in contract execution dates is 6 months or less; or (2) the contracts do not specify the generation source, are with the same supplier, specify the same delivery point, and are executed within 24 hours."

184. The purpose of requiring "linked" contacts -- for baseload generation -- that have a combined term of 5 years or more to comply with the EPS is to prevent LSEs from circumventing the EPS by splitting up a single commitment into multiple contracts (or using a contractual option in place of a binding contract).

185. Requiring that contracts with an unspecified generation source must be executed within 24 hours of each other to be considered linked would make it too easy to circumvent the EPS.

186. The date of execution of the contracts, standing alone, should not be the determining factor in deciding whether two contracts are sufficiently related to be considered one for purposes of applying the EPS.

187. Two contracts should be considered linked if both of them are negotiated or executed within a specified time-window. (For more than two contracts to be "linked" all of them would have to be negotiated or executed within the same window of time.)

188. A window period of three months should be sufficient for both specified and unspecified contracts.

189. Because it is possible for power from the same powerplant (or group of powerplants) to be delivered to the LSE at different points, we conclude that a requirement that in order for two "unspecified" contracts to be linked they must

"specify the same delivery point" would make it too easy to evade the EPS by splitting up a single deal into two contracts with different delivery points.

190. The linkage rule should use the term "powerplant" rather than "generating unit" to be consistent with the terminology used throughout these EPS rules.

191. Two contracts should not be considered linked if they are entered into as a result of separate RFOs and the contract from the earlier RFO is executed before the later RFO has received bids, because in that situation it is clear that each contract was negotiated separately.

192. SCE's suggestion that if "two contracts are 'independent' of each other, [i.e., if selection of one does not require selection of the other] the Commission should not consider them to be 'linked'" should be rejected, because it does not contain sufficiently clear guidelines to enable an LSE to determine if two contracts will be considered linked.

193. In order to prevent circumvention of the EPS, both binding contracts and contractual options should be analyzed to see whether they are "linked" and if so, whether their "term" is for five years or more.

194. A linkage rule is only the initial step in determining whether a particular group of linked contracts must comply with the EPS. It is simply used to determine whether the length of the linked contracts is sufficient for there to be a contract with a term of five years or more.

195. Defining the term "annualized" in § 8340(a) to mean "annual average" is reasonable based on the common definition of the word "annualize," namely "to calculate or adjust to reflect a rate based on a full year."

196. For the purpose of calculating the plant capacity factor, using the maximum output allowed under the powerplant's operating permit in the

denominator of the equation will best captures the "designed *and intended*" language of the statute in those instances when permit provisions represent the effective constraint on the maximum output of the facility, rather than the manufacturer's rated capacity.

197. To be applied in a manner that is consistent with this decision, the annual average capacity factor must be calculated based on the annual production of the underlying facility, and not just what might be delivered under a specific contract with an LSE.

198. A plant's operations may vary significantly from year to year, based on weather, maintenance schedules or economic conditions.

199. There are likely to be situations where more than a single year of annual electricity production will need to be considered in determining whether or not a powerplant is a baseload facility as defined under § 8340(a), i.e., whether it is "designed and intended" to provide electricity at an annualized plant capacity factor of at least 60 percent.

200. The definition of "plant capacity factor" under § 83401(l) provides for consideration of more than a single year, in that it expresses the capacity factor as a ratio of electricity produced to electricity production at rated capacity "during a given time period."

201. SCE, PG&E and SDG&E are in the process of preparing and submitting long-term procurement plans for Commission pre-approval in R.06-02-013, and may need to update those plans to reflect how they will comply with today's decision.

202. Developing or clarifying the Commission's overall policies with respect to zero or low-carbon generation resources is beyond the scope of Phase 1.

203. The long-term procurement rulemaking, R.06-02-013 or its successor proceeding, is the appropriate procedural forum for the Commission's consideration of any requests by electrical corporations for § 8341(b)(6) rate-of-return increases on investments made by third parties.

204. Calpine's recommendation that the Commission take additional steps to encourage long-term commitments with resources with emissions below the EPS limit, including providing financial incentives, is beyond the scope of Phase 1.

205. Going beyond the specific direction of SB 1368 by taking a lifecycle approach to net emissions calculations, as CE Council suggests in its comments on the Proposed Decision with respect to LNG facilities, was not raised during the scoping of Phase 1, during workshops or in pre- or post-workshop written comments. Even if it were, we do not have a sufficient record or time before the statute requires us to adopt an enforceable standard to take this approach for the interim EPS.

206. It would be premature, and beyond the scope of Phase 1, to establish target dates in today's decision for the determination of emission allowances under a load-based cap, as recommended by San Francisco Community Power in their comments.

207. An LSE is free to enter into long-term contracts with both in-state and out-of-state generators because the EPS makes no distinction between in-state and out-of-state sources of electricity.

208. Under the EPS, electricity generated from high-GHG emitters can still be sold to California LSEs under existing contracts, or under new or renewal contracts of less than five years.

209. Coal-fired and other plants that use technology to reduce GHG emissions could meet the EPS.

210. Under the EPS, a substantial amount of electricity generated out-of-state would meet the EPS and therefore continue to be available for procurement.

211. Nothing in the EPS prohibits high-GHG emitters from transmitting electricity through the California grid to other states and nations.

212. Many local low-capacity generators are required to generate electricity at specific locations for the operational reliability of the electric transmission grid.

213. Long-term baseload generation operating at a capacity factor of 60% or greater performs a totally different function and would be responsible for a much greater amount of GHG emissions than low-capacity factor generation (such as peakers) operating at a capacity factor of less than 60%, including many which are operating at only 10% or 20% of the time during the year and essential for the reliability of the grid.

214. The generators competing under the EPS for long-term, high-capacity baseload contracts are not similarly situated with low-capacity generation plants.

215. The EPS does not give California firms any competitive advantage over out-of-state firms.

216. By setting a GHG emissions limit, the EPS would create an incentive to further the development of clean coal technology, rather than hinder it.

217. Beyond a specific class of high-GHG emitters seeking to sell to California LSEs, out-of-state generators would generally be able to meet the EPS.

218. As the Legislature found in SB 1368, global warming will have devastating impacts on the economy, health and environment of the State of California.

219. The EPS is indifferent to electric sales to entities in other states.

220. In developing the interim EPS, the Commission has considered the effects on reliability and overall costs to electric customers in the following ways:

a. By designing the EPS so that it functions similar to an appliance efficiency standard and thereby:
    i. Protecting electricity customers from reliability problems and high compliance costs in the future, and
    ii. Reducing GHG emissions that will mitigate adverse impacts on the economy, health and environment, which reduces overall costs to all Californians, including electricity customers.
b. By defining covered procurements as new long-term commitments to baseload generation, which:
    i. Captures the largest percentage of impact on GHG emissions,
    ii. Excludes the types of procurements that the LSE is most likely to need for system reliability requirements (e.g., short-term power purchases, long-term contracts with load-following and peaking generation facilities, or new construction of non-baseload powerplants), and
    iii. Focuses compliance on the types of facilities over which the LSE has the most discretion and choice, thereby minimizing the costs of compliance to the LSE and its electricity customers.
c. By not subjecting the millions of dollars in the LSE's already-built facilities to a standard that is being developed to prevent backsliding in LSE decisions made for future investments.
d. By providing for Commission review of reliability exemptions on a case-by-case basis in the event that unforeseen reliability concerns and associated costs arise during implementation of the EPS.

221. No showing has been made in this proceeding that new, EPS-compliant procurements will not be available at reasonable costs to ratepayers.

Conclusions of Law

1. For the reasons discussed in this decision, it is reasonable to limit today's adopted EPS to CO_2 emissions, at least at this time.

2. Pursuant to SB 1368, the EPS adopted today should apply to every electrical corporation, electric service provider or community choice aggregator serving end-use customers in the state, as the statute defines those terms.

3. The interim EPS should apply to baseload generation as that term is defined in SB 1368.

4. Constellation's proposal for defining covered procurements is not reasonable in light of the plain language of SB 1368, legislative history and the objectives of this Commission and the Legislature for an interim EPS, and should be rejected.

5. The interim EPS should define "long-term financial commitment" as set forth in § 8340(g) of SB 1368.

6. SCE's interpretation of "new ownership investment" to only encompass an investment in baseload generation that is *also* a new ownership interest is not reasonable for the reasons discussed in this decision, and should be rejected.

7. We conclude from our reading of SB 1368 that the term "new ownership investment" under SB 1368 encompasses new LSE investments in retained baseload generation.

8. As discussed in this decision, excluding retained generation from EPS-covered procurements (unless a review is triggered by a new "long-term financial commitment" as defined under SB 1368) is fully consistent with the principles and objectives for an interim EPS articulated by the Legislature and this Commission.

9. As discussed in this decision, reading the definition of "powerplant" in SB 1368 to mean that a powerplant (facility) may be comprised of one or more generating units at the same location—but not that is necessarily follows that *all* of the units at the same location comprise a single powerplant (facility)—is consistent with the language and intent of SB 1368, and avoids absurd results.

10. The clarifications in today's decision of what constitutes a multi-unit powerplant for the purpose of applying the EPS rule are reasonable and should be adopted.

11. For the reasons discussed in this decision, we conclude that it is reasonable and consistent with the direction of SB 1368 to apply the EPS to the following "covered procurements":

(1) New ownership investments in baseload generation made by an LSE, defined as:
   (a) Investments in new baseload powerplant (new construction), or
   (b) Acquisition of new or additional ownership interest in existing baseload powerplant previously owned by others, or
   (c) New investments in the LSE's own existing, non-CCGT baseload powerplants that are:
      (i) designed and intended to extend the life of one or more units by five years or more,
      (ii) result in a net increase in the rated capacity of the powerplant, or
      (iii) designed and intended to convert a non-baseload plant to a baseload plant, or
   (d) Units added to a deemed-compliant CCGT powerplant that result in an increase of 50 MW or more to the powerplant's rated capacity (the LSE owner need only show that the added units meet the EPS), or

(2) New contract commitments (including renewal contracts) of five years or greater by an LSE with:

(a) baseload generation facilities, unless those facilities represent deemed-compliant CCGT powerplants, or

(b) any deemed-compliant CCGT powerplant that added units resulting in an increase of 50 MW or more to the powerplant's rated capacity. (The contracting LSE need only show that the added units meet the EPS.)

12. For the purpose of determining the "term" of a contract under these EPS rules, two or more contracts, including contractual options, should be treated as one ("linked"), where:

A. (1) They specify the same powerplant as the primary delivery source or, (2) for an unspecified source, they are with the same counter-party;

and

B. They are negotiated or executed within any three consecutive-month period, except if entered into as a result of separate RFOs and the contract from the earlier RFO is executed before the later RFO has received any bids (either indicative or final).

13. The Commission retains the right to address questions related to the maintenance and efficiency of CCGT powerplants including but not limited to, the emissions from these plants, in the investor-owned utility general rate cases, long-term procurement plans, or other appropriate proceedings.

14. SDG&E/SoCalGas' suggestion that we establish the EPS level high enough to ensure that all deemed-compliant CCGTs could meet the standard is inconsistent with the Legislature's direction to deem them to be in compliance, based on the common definition of the term "deem," and should be rejected.

15. EPUC/CAC's suggestion that we establish an EPS level high enough to ensure that all gas-fired units meet that level is inconsistent with the direction of SB 1368, and should be rejected.

16. Based on the record in this proceeding and direction of SB 1368, an EPS performance level of 1,100 lbs. of CO2 per MWh is reasonable and should be adopted.

17. Determining whether the EPS applies to a contract commitment should be made based on a "facility" basis, i.e., based on the characteristics of each generating source underlying the contract, and not on the contracted-for deliveries. This application of the EPS will further the policy objectives of SB 1368 and is supported by the rules of statutory construction.

18. Applying the EPS to the underlying facility in the case of customer generators does not exceed the Commission's jurisdiction or violate any laws, as some parties contend in this proceeding.

19. As discussed in this decision, a blanket exemption from the requirement to examine the capacity factor of the underlying facility for partial contracts is both unnecessary and inconsistent with other aspects of the EPS we adopt today.

20. For the reasons discussed in this decision, a small facility, commitment or service territory size exemption from the requirement to comply with the EPS should not be adopted, except as specifically provided for under § 8341(d)(9) for multi-jurisdictional electrical corporations that meet the alternative compliance requirements of that section.

21. Under federal law, California electric utilities are required to purchase energy from QFs.

22. Nothing in the language of PURPA or FERC's regulations requires utilities to offer QFs long-term contracts (contracts of five years or more).

23. Under SB 1368, electric utilities will still be required to purchase energy from QFs in compliance with PURPA. For those QFs that do not meet the EPS,

utilities can meet the purchase obligation through contracts of less than five years.

24. Neither SB 1368 nor the Commission's implementation of it conflict with PURPA.

25. SB 1368 does not allow this Commission to provide exemptions for QFs unless application of the EPS would conflict with PURPA.

26. QFs should not be exempt from compliance with SB 1368.

27. It is reasonable and consistent with the language of SB 1368 to require EPS compliance of all covered procurements with gas-fired cogeneration facilities, including existing facilities and bottoming-cycle technologies.

28. Subject to the caveats discussed in this decision, it is reasonable to permit requests for reliability exemptions on a case-by-case basis, including reliability exemptions from the requirement that all covered procurements must be with specified resources.

29. Any consideration of reliability exemptions or requests to be excused from the requirements of this decision due to "extraordinary circumstances, catastrophic events or threat of significant financial harm" comes with a heavy burden of proof on the LSE. Any such requests should be pre-approved by this Commission.

30. Pursuant to § 8341(d)(6), the Commission has consulted with the California ISO during the development of the interim EPS rules and should continue to consult with the ISO during implementation in considering the effects of requests for reliability exemptions on system reliability and overall costs to electricity customers.

31. Approaches that would require us to assess costs or economic impacts on a case-by-case procurement basis are neither reasonable nor workable in the context of complying with the provisions of SB 1368.

32. LSEs should not petition to be excused from the requirements of this decision unless they can clearly demonstrate that: (1) they are facing extraordinary circumstances, catastrophic events or threat of significant financial harm not contemplated by SB 1368 and this decision, and (2) an exemption from some requirement of this decision is necessary to significantly mitigate or eliminate the challenges posed by these circumstances.

33. It is reasonable to adopt the Conversion Method of calculating cogeneration emissions rates for the purpose of determining compliance with the interim EPS, with the clarification that the Btu Thermal Energy Output (expressed in kWh) in the formula represents "useful thermal energy" as defined in the FERC regulations implementing QF policy under PURPA.

34. Today's adopted approach for calculating and documenting cogeneration emissions rates for the interim EPS should not prejudge or predetermine the approach to be established in the context of the Commission's Procurement Incentive Framework or under the statewide GHG emissions limit envisioned under AB 32.

35. Based on the record in this proceeding, it is reasonable to make an upfront determination that the following renewable resources and technologies are EPS-compliant:

(a) Solar Thermal Electric(with up to 25% gas heat input)

(b) Wind

(c) Geothermal, with or without reinjection

(d) Generating facilities (e.g., agricultural and wood waste, landfill gas) using biomass that would otherwise be

> disposed of utilizing open burning, forest accumulation, landfill (uncontrolled, gas collection with flare, gas collection with engine), spreading or composting.

36. If and when there is sufficient data so that parties believe that the Commission could make determinations for pre-approval of additional renewable resources and technologies, it is reasonable to permit parties to file a Petition for Modification of this decision to augment the above list.

37. For the reasons discussed in this decision, the emissions profile of a renewable facility should not change if or when it sells RECs under a future regulatory REC market for the purpose of demonstrating EPS compliance. Nor should RECs count towards compliance with the interim EPS by those LSEs who may purchase them for RPS compliance purposes in the future.

38. Today's determinations on how to treat null renewable power and associated RECs in the context of the interim EPS should not be construed to mean that null renewable power will be assigned a zero or low GHG emissions value in the context of the Procurement Incentive Framework we are implementing in Phase 2 of this proceeding, or the statewide GHG emissions limits adopted by the Legislature in AB 32.

39. Adopting an approach to unspecified contracts that involves the use of proxy estimates for emissions rates would not further the goals of SB 1368 and would be problematic from an implementation standpoint.

40. For the reasons discussed in this decision, it is reasonable and consistent with the intent of SB 1368 to require for the interim EPS rules that all contracts with a term of five years or more be with specified resources that can demonstrate EPS compliance (or demonstrate that compliance is not required), except when substitute system energy is purchased to firm deliveries from specified powerplants under the following circumstances:

1. The contract is with one or more specified powerplants, each of which is EPS-compliant under our adopted rules.
2. For specified contracts with non-renewable resources or dispatchable renewable resources (or a combination of each), substitute energy purchases for each specified powerplant are permitted up to 15% of forecast energy production of the specified powerplant over the term of the contract, provided that the contract only permits the seller to purchase system energy under either of the following conditions:
   a) The contract permits the seller to provide system energy when the powerplant is unavailable due to a forced outage, scheduled maintenance or other temporary unavailability for operational or efficiency reasons; or
   b) The contract permits the seller to provide system energy to meet operating conditions required under the contract, such as provisions for number of start-ups, ramp rates, minimum number of operating hours, etc.

   A "dispatchable" renewable resource for the purpose of this rule is one that is not defined as "intermittent" under section 3 below.
3. For specified contracts with intermittent renewable resources (defined as solar, wind and run-of-river hydroelectricity), the amount of substitute energy purchases from unspecified resources is limited such that total purchases under the contract (whether from the intermittent renewable resource or from substitute unspecified sources) do not exceed the total expected output of the specified renewable powerplant over the term of the contract.

41. A gateway screen approach to determining compliance with the interim EPS is reasonable and should be adopted.

42. Under § 8341(a), LSEs must comply with SB 1368 if they enter into any long-term financial commitment involving baseload generation, irrespective of whether (or how) this Commission reviews and approves such commitments. Under §§ 8341(a) and (b), in adopting rules and procedures to ensure compliance

with the EPS, we have the flexibility under the statute to consider a range of procedural vehicles for use by those LSEs for whom we do not currently have a procurement pre-approval process in place.

43. The procedures and documentation requirements for a showing of compliance with the EPS gateway screen required of large electrical corporations, small electrical corporations, electric service providers and community choice aggregators, as set forth in this decision, are reasonable and should be adopted.

44. No after-the-fact Attestation Letter or Advice Letter request for pre-approval of covered procurements submitted in compliance with the Interim EPS Rules should be "deemed approved," as may be permitted under the Commission's current or future Advice Letter procedures in R.98-07-038 or R.06-05-027, or their successor proceedings.

45. As discussed in this decision, consideration of a reliability exemption to the EPS or request for an "extraordinary circumstances" modification of this decision should come with a heavy burden of proof on the LSE, as it must be based on extreme (and therefore highly unlikely) circumstances.

46. As discussed in this decision, the Commission should consider any request for a reliability exemption or "extraordinary circumstances" modification on a case-by-case basis. LSE requests for pre-approval of a reliability exemption should be made by application. LSE requests to obtain "extraordinary circumstances" relief from this decision should be made by filing a petition for modification.

47. Because of the unique nature of CO_2 geological injection sequestration projects, an LSE entering into an EPS covered procurement utilizing such projects should request Commission pre-approval by application. In order to

ensure that the purposes of SB 1368 are served, the LSE should be required to (1) provide documentation that the project has a reasonable and economically and technically feasible plan that will result in the permanent sequestration of CO_2 once the injection project is operational and (2) present projections (and documentation of those projections) of net emissions over the life of the powerplant, and (3) provide documentation that the CO_2 injection project complies with applicable laws and regulations.

48. PacifiCorp's three alternative compliance tests for a showing under § 8341(d)(9)(B) are reasonable and should be adopted.

49. It is consistent with Section 8341(d)(9) to exclude PacifiCorp and Sierra Pacific from the EPS Interim Rules since they have demonstrated that they qualify for alternative compliance.

50. Multi-jurisdictional utilities that qualify for alternative compliance should still be required to file annual advice letter on February 1 of each year attesting that they continue to meet the alternative compliance requirements.

51. For the reasons discussed in this decision, our rules for demonstrating compliance with the interim EPS should not permit offsets or portfolio averaging. However, nothing in today's decision should be construed as precluding consideration of these and other compliance options in the context of Phase 2, when this Commission will be addressing the implementation of the load-based GHG emissions cap adopted in D.06-02-032.

52. Consistent with the definition of plant capacity factor provided in SB 1368 and today's decision, the term "annualized plant capacity factor" should be defined as: "the ratio of the annual amount of electricity produced, measured in kilowatt hours, divided by the annual amount of electricity the unit could have

produced if it had been operated at its maximum permitted capacity, expressed in kilowatt hours.

53. In order to determine whether the plant is "designed and intended" to provide electricity at an annualized plant capacity factor of at least 60 percent, LSEs should include historical plant capacity factors for the underlying facility or facilities in their documentation of whether the EPS applies to a new long-term financial commitment (other than new plant construction).

54. SCE, PG&E and SDG&E should update their long-term procurement plans in R.06-02-013 in compliance with the EPS, as necessary, to reflect today's determinations.

55. If electric service providers and community choice aggregators are required by the Commission to file long-term procurement plans in the future, they should describe in those filings how they plan on complying with EPS.

56. CEED cites authorities which may show that the United States has a foreign policy of not entering into treaties that do not require the curbing of C02 emissions from developing nations.

57. This Commission is not proposing to enter into any treaties or agreements with foreign governments or entities.

58. When, and if, the U.S. does sign a GHG treaty or otherwise promulgates a GHG policy that is binding on the states, this Commission will be required to bring its program into compliance if there is a conflict.

59. Statements by representatives of the federal government show that the federal government acknowledges and supports states' efforts to reduce GHG emissions.

60. Neither SB 1368 nor the Commission's implementation of it conflict with federal foreign policy.

61. No party has cited to any provision in the Global Climate Protection Act of 1987 (GCPA), or the Energy Policy Acts of 1992 and 2005, that preempts states from requiring their utilities to take actions to decrease GHG emissions.

62. The Global Climate Protection Act of 1987 (GCPA), and the Energy Policy Acts of 1992 and 2005 include provisions that acknowledge states' role in regulating GHG emissions and that contemplate states' participation in the reduction of GHG emissions.

63. Neither SB 1368 nor the Commission's implementation of it conflict with either the Global Climate Protection Act of 1987 (GCPA), or the Energy Policy Acts of 1992 and 2005.

64. The EPS regulates LSEs, which sell electric energy in the retail market in California.

65. The EPS is a component of the regulation of procurement practices of the retail sellers of electric energy in California.

66. The EPS is not regulating wholesale generators or marketers.

67. Under the Federal Power Act, FERC does not have jurisdiction over retail sellers of electric energy, including their procurement decisions.

68. The Federal Power Act does not preempt state regulation of procurement choices by retail sellers of electric energy, including programs designed to reduce GHG emissions, such as the EPS.

69. Any party challenging the constitutional validity of the EPS under the dormant Commerce Clause bears the burden of demonstrating discrimination.

70. The EPS does not discriminate based on geographic origin.

71. Because low-capacity generators are not similarly situated with plants subject to the EPS, the exemption of low-capacity factor generators from the EPS cannot constitute discrimination against interstate commerce.

72. The dormant Commerce Clause does not require California to protect the pecuniary interests of out-of-state coal burners.

73. The Commerce Clause protects the interstate market, not particular interstate firms, from prohibitive or burdensome regulations.

74. Any shift towards or away from out-of-state resources is speculative at this point, and could not possibly indicate discriminatory intent.

75. The EPS is an evenhanded regulation that lacks discriminatory intent or effect as to interstate commerce.

76. When a state enactment is not facially discriminatory, the *Pike* balancing test is generally applied.

77. A regulation's burdens on interstate commerce must be "clearly excessive" in relation to the local benefits in order for a regulation to be struck down under *Pike*.

78. The burden of proving "excessiveness" under *Pike* falls on the party challenging a regulation.

79. The EPS has substantial local benefits.

80. Selectively characterizing the interstate market does not necessarily establish an impermissible burden on interstate commerce.

81. While national displacement of coal may have some economic effects, this does not establish an impermissible burden on interstate commerce

82. The "burdens" on interstate commerce, alleged by CEED and others, are incidental and not "clearly excessive" in relation to the substantial local benefits of the EPS.

83. Extraterritorial regulation means regulation that impacts commerce that occurs "wholly" outside the state.

84. When a state regulates contractual relationships in which at least one party is located within California, it does not regulate commerce entirely outside of the State of California.

85. Simply because the sales to California LSEs under the EPS may affect the costs or profits of an out-of-state generation company, this does not make the regulation extraterritorial.

86. The EPS does not have an impermissible extraterritorial reach.

87. The EPS is valid under the dormant Commerce Clause.

88. In developing the interim EPS, the Commission has considered the effects of the standard on system reliability and overall costs to electricity customers as required under § 8341(d)(6).

89. The interim EPS fulfills both the letter and the spirit of SB 1368 by effectively "raising the bar" for the GHG emissions performance of new long-term commitments with baseload generation serving California during the transition to a statewide GHG emissions cap.

90. In order to meet the February 1, 2007 deadline established by SB 1368 for the adoption of an enforceable interim EPS, this decision should be effective immediately.

INTERIM ORDER

IT IS ORDERED that:

1. As defined in Senate Bill (SB) 1368 (Stats. 2006, ch. 598) and by today's decision, every electrical corporation, electric service provider, or community choice aggregator serving end-use customers in the state (collectively referred to as "load-serving entities" or "LSEs") shall be subject to the greenhouse gas

interim emissions performance standard rules ("Interim EPS Rules") described in this decision and set forth in Attachment 7.

2. The Interim EPS Rules presented in Attachment 7 and described in this decision shall be effective and enforceable immediately.

3. Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE) and San Diego Gas & Electric Company (SDG&E) shall submit for Commission pre-approval all procurements subject to the Interim EPS Rules ("covered procurements") as follows:

(a) For covered procurements eligible under the Renewable Portfolio Standard (RPS) program:

i. PG&E, SCE and SDG&E shall request pre-approval through RPS advice letter filings, and

ii. These advice letters shall be served on the service list in Rulemaking (R.) 06-05-027, or its successor proceeding.

iii. Should an application process be used for any particular RPS contract, or should the advice letter process set forth in Decision (D.) 03-06-071 be changed in whole or in part to an application process in the future, that application process shall automatically apply to the EPS compliance filings required of PG&E, SCE and SDG&E for RPS resources. However, if the advice letter process set forth in D.03-06-071 is modified to include procedures whereby RPS advice letters may be "deemed approved," such procedures shall not apply for the purpose of establishing EPS compliance.

(b) For covered procurements with non-RPS generation:

i. PG&E, SCE and SDG&E shall request pre-approval through the non-RPS application process established by the Commission's procurement rules in R.06-02-013, or its successor proceeding, and

ii. These applications shall be served on the service list in R.06-02-013, or its successor proceeding.

(c) For covered procurements that employ geological formation injection for carbon dioxide (CO_2) sequestration:

i. PG&E, SCE and SDG&E shall request pre-approval through the non-RPS application process established by the Commission's procurement rules in R.06-02-013, or its successor proceeding, and

ii. As part of this filing, PG&E, SCE and SDG&E shall provide documentation demonstrating that the CO_2 capture, transportation and geological formation injection project has a reasonable and economically and technically feasible plan that will result in the permanent sequestration of CO_2 once the project is operational, and that the CO_2 injection project complies with applicable laws and regulations. This showing shall include any emissions-related provisions that may be required through contract and/or permit conditions.

iii. These applications shall be served on the service lists in R.06-02-013 and this proceeding, or their successor proceedings.

4. All LSEs other than PG&E, SCE and SDG&E are required to file annual Attestation Letters, due by February 15 of each year, attesting to the Commission that the financial commitments entered into during the prior calendar year are in compliance with the EPS. The Attestation Letter shall include a certification, including the name and contract information for the LSE officer(s) certifying the following under penalty of perjury:

A. I have reviewed, or have caused to be reviewed, this compliance submittal.

B. Based on my knowledge, information, or belief, this compliance submittal does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements true.

C. Based on my knowledge, information, or belief, this compliance submittal contains all of the information required to be provided by Commission orders, rules and regulations.

The Attestation Letter shall be filed as an advice letter and served on the service list in this proceeding, or its successor proceeding. The Attestation Letter shall be subject to the Commission procedures governing advice letter filings, which include opportunity for protests and responses. However, no Attestation Letter shall be "deemed approved" under those procedures.

Energy Division shall review each Attestation Letter and approve it if it contains all the elements required by the EPS documentation requirements, includes a certification by the responsible corporate officers, and if the facts stated in the Attestation Letter show compliance with the EPS. Energy Division approval of the Attestation Letter means that the Attestation Letter is in compliance with these rules, and that any procurements *as reported in the Attestation Letter* comply with the requirements of the EPS program. Energy Division approval does not mean that LSE procurements that are unreported or inaccurately reported comply with the EPS. LSEs shall be subject to penalties if the attestation letters are found, at a later date, to be incomplete, misleading or incorrect.

5. Except as otherwise directed under Ordering Paragraphs 6, 7 and 8, LSEs other than PG&E, SCE and SDG&E may submit advice letters during the year requesting pre-approval of a new financial commitment as EPS compliant, at their discretion. These advice letter filings, as well as any responses or protests, shall be served on the service list in this proceeding or its successor proceeding. The advice letter shall be subject to the Commission procedures governing advice letter filings, which include opportunity for protests and responses. However, no advice letter submitted for this purpose shall be "deemed approved" under those procedures.

6. For covered procurements that employ geological formation injection for CO_2 sequestration, LSEs other than PG&E, SCE and SDG&E shall request Commission pre-approval by filing a separate application with service on the service list in this proceeding, or its successor proceeding. As part of this filing, the LSE shall provide documentation demonstrating that the CO_2 capture, transportation and geological formation injection project has a reasonable and economically and technically feasible plan that will result in permanent sequestration of CO_2 once the injection project is operational and that the CO_2 injection project complies with applicable laws and regulations. The LSE shall also make a showing of EPS compliance by presenting projections, and documentation of those projections, of net emissions over the life of the powerplant. This showing shall include any emissions-related provisions that may be required through contract and/or permit conditions.

7. Any request for a reliability exemption shall require Commission pre-approval and shall be made by separate application, as follows:

(a) PG&E, SCE and SDG&E shall serve such requests on the service lists in R.06-02-013 and this proceeding, or their successor proceedings, and

(b) All other LSEs shall service such requests on the service list in this proceeding.

Any LSE requesting review and pre-approval of a reliability-based exemption from the EPS rule shall provide documentation demonstrating that such long-term procurements are necessary to ensure system reliability. As discussed in this decision, the Commission shall consult with the California Independent System Operator during implementation in considering the effects of requests for reliability exemptions on system reliability and overall costs to electricity customers.

8. LSEs shall not ask to be excused from the requirements of this decision for any other reason unless they can clearly demonstrate:

(a) They are facing extraordinary circumstances, catastrophic events or threat of significant financial harm not contemplated by SB 1368 and this decision, and

(b) An exemption from some requirement of this decision is necessary to significantly mitigate or eliminate the challenges posed by these circumstances.

Any requests to be excused from the requirements of this decision for such "extraordinary circumstances" must be pre-approved by the Commission and shall be made as a petition for modification of this decision and served on the service list in this proceeding, or its successor proceeding.

9. The Commission's consideration of any request for a reliability exemption or petition for modification to be excused from the requirements of this decision due to "extraordinary circumstances, catastrophic events or threat of significant financial harm" shall come with a heavy burden of proof on the LSE.

10. In the compliance submittals required under Ordering Paragraphs 3 and 4 above, all LSEs shall include a listing of the new long-term financial commitments of five years or longer they plan to enter into (SCE, PG&E and SDG&E) or have entered into during the prior year (all other LSEs) with documentation to demonstrate:

(a) That the commitments are not "covered procurements" under the Interim EPS Rules and/or

(b) For those that represent covered procurements, documentation demonstrating that such procurements are EPS-compliant, including any contracts with a term of five years or longer that include provisions for substitute energy purchases.

(c) For any requested reliability-based exemptions that have been pre-approved by the Commission, a reference to the application and Commission decision number.

Consistent with the discussion in this decision that "linked" contracts are to be treated as a single contract for purposes of EPS compliance, this listing of new long-term financial commitments of five years or longer must include any "linked" contracts whose combined term is five years or longer. LSEs are also advised to present documentation regarding the design and intended use of the powerplant(s) underlying the new long-term financial commitments utilizing the sources of documentation listed under § 8341(b)(4) of the Public Utilities Code, as well as any other sources of documentation that they believe will be relevant to the Commission's determination of whether the commitment represents a "covered procurement" under the Interim EPS Rules. As discussed in this decision, LSEs are required to include historical annual averages in their documentation of annualized plant capacity factors. In documenting the emissions rates associated with covered procurements, LSEs shall comply with the Interim EPS Rules governing the calculation of those rates, which include the adopted method for cogeneration facilities.

11. The burden is on the LSE to document that the limits to substitute energy purchases with unspecified resources described in this decision are reflected in any contracts with a term of five years or longer that include substitute energy provisions. In particular, the LSE shall make available to Commission staff the source data and methodology it uses in developing the level of expected output from renewable resources under contracts with a term of five years or longer that permit substitute energy purchases from unspecified resources, in order to demonstrate that the limits for substitute energy purchases for both intermittent and dispatchable renewable resources were properly established under the substitute energy provisions.

12. In addition to other documentation required by this decision, all LSEs shall disclose their investments in retained generation, including combined-cycle gas turbine (CCGT) powerplants deemed to be in compliance under § 8341(d)(1). This information shall describe the investment amount and type of alteration by generation facility and unit. PG&E, SCE and SDG&E shall disclose this information in their Quarterly Procurement Plan Compliance Reports established by D.02-10-062. All other LSEs shall disclose this information in the annual Attestation Letter required under Ordering Paragraph 4.

13. The advice letter procedures for the annual Attestation Letters and other compliance submittals described in this decision are adopted for the limited purpose of EPS compliance. In the event that some clarifications or modifications to these procedures may need to be made after the effective date of this decision in order to reconcile them with updated Commission procedures for advice letter filings in R.98-07-038 or R.06-05-027, or their successor proceedings, the Assigned Commissioner shall provide such clarifications or modifications by ruling or other manner, in consultation with the assigned Administrative Law Judge (ALJ) and Energy Division.

14. Sierra Pacific Power Company and PacifiCorp are excused from showing compliance with the Interim EPS Rules based on their showing of alternative compliance. They are still required, however, to file annual attestation letters on February 1 of each year, beginning February 1, 2008, stating that they continue to qualify for alternative compliance consistent with this decision.

15. Within sixty (60) days from the effective date of this decision, SCE, PG&E and SDG&E shall update their long-term procurement plan (LTPP) filings in R.06-02-013 in compliance with the Interim EPS Rules, as necessary, to reflect today's determinations. If changes to the LTPP filings are necessary to show

compliance with this decision, SCE, PG&E and SDG&E will file an Amendment to the LTPP, Volume 1, indicating whether the Amendment supersedes or adds to specific sections of the plan, with service on the service list in R.06-02-013.

16. As discussed in this decision, the Commission, Assigned Commissioner ALJ and/or Commission staff retain the right to data request any of the LSEs, including the electric service providers, community choice aggregators or small electrical corporations, to ask for any copies of contracts or procurement information that is deemed necessary to evaluate compliance with the EPS. Any LSE may be audited if the Commission or staff has any doubt that the LSE is forthcoming in its demonstration of EPS compliance.

17. If any of the financial commitments entered into by LSEs appear to be out of compliance with the Interim EPS Rules, the Commission may consider issuing an Order Instituting Investigation (OII) or take other appropriate action. If the Commission finds that the LSE did not comply with those rules, the Commission shall address the level of penalties in an OII proceeding or other procedural forum, as it deems appropriate.

18. Any LSE that seeks confidentiality protection for data contained in its EPS-related submittals shall follow the policies and procedures set forth in D.06-06-066.

This order is effective today.

Dated January 25, 2007, at San Francisco, California.

MICHAEL R. PEEVEY
President
DIAN M. GRUENEICH
JOHN A. BOHN

RACHELLE B. CHONG
Commissioners

D0701039 Figures 1 & 2 and Attachments 1-7